Present: Carrico, C. J., Compton, Stephenson, Whiting, Lacy, and Keenan, JJ., and Poff, Senior Justice

Record No. 940885

HOPEWELL COGENERATION LIMITED PARTNERSHIP

v.

STATE CORPORATION COMMISSION

Record No. 940886

ENRON-RICHMOND POWER CORP.

v.

STATE CORPORATION COMMISSION

Record No. 940887

COGENTRIX VIRGINIA LEASING CORP.

v.

STATE CORPORATION COMMISSION

Record No. 940888

APPOMATTOX COGENERATION LIMITED PARTNERSHIP

v.

STATE CORPORATION COMMISSION

Record No. 940901

CHESAPEAKE PAPER PRODUCTS COMPANY
v.
STATE CORPORATION COMMISSION

Record No. 940902

VIRGINIA ELECTRIC AND POWER COMPANY
v.
STATE CORPORATION COMMISSION

FROM THE STATE CORPORATION COMMISSION

OPINION BY JUSTICE ELIZABETH B. LACY
January 13, 1995

In this utility rate case appeal, we consider whether the State Corporation Commission properly eliminated certain expenses associated with the purchase of electric power from the rate base of Virginia Electric and Power Company (Virginia Power), thereby disallowing recovery of those expenses through the rates charged the utility's electric customers.

On May 29, 1992, Virginia Power filed an application to increase its electric rates by an amount which would produce total annual operating revenues of $3,362,002,000. The application was divided into three phases with hearings held on each phase. Phase III addressed the expenses at issue here. The disputed expenses are a component of the amounts Virginia Power pays for electric power purchased from non-utility generators.

Utility purchases of electric power from non-utility generators are required by the Public Utility Regulatory Policies Act of 1978 (PURPA). 16 U.S.C. § 824 (1985). The rate a utility pays a non-utility generator for purchased power is regulated, at least in part, by federal statute and regulations. The rate must be just and reasonable, may not discriminate against small power producers, and may not exceed the "incremental cost to the electric utility of alternative electric energy." 16 U.S.C. § 824a-3(b) (1985); 18 C.F.R. § 292.304(a) (1994). The "incremental cost" is the amount the utility saves by not constructing new power generation facilities, 16 U.S.C. § 824a-3(d) (1985), 18 C.F.R. § 292.101(b)(6) (1994), and is generally referred to as the utility's "avoided cost."

Avoided cost rates cannot be calculated with precision. They depend on a number of assumptions, data inputs, estimates, and calculations. Recognizing the variables inherent in determining this type of rate, the Federal Energy Regulatory Commission (FERC) adopted regulations to guide such determinations. In those regulations, the FERC determined that, where the rate is based on estimates of the avoided costs over the life of the contract, the rate does not violate federal standards if it differs from the avoided costs at the time of the power's actual delivery. 18 C.F.R. § 292.304(b)(5) (1994). The FERC also concluded that, although the supply characteristics affecting the avoided costs may vary among generators, without standardized rates, the transaction costs associated with determining individualized rates for small power producers could make the program uneconomic for these generators. Order No. 69, Docket No. 79-55, FERC Statutes and Regulations, Regulations Preambles 1977-1981, ¶ 30,128 at 30,878 (1980). Consequently, the regulations require the states to

adopt standardized avoided cost rates that non-utility generators with design capacities of 100 kilowatts or less can utilize.[1] 18 C.F.R. § 292.304(c) (1994). Finally, the states were directed to develop rules to implement PURPA and its regulations. 16 U.S.C. § 824a-3(f)(1) (1985).

In 1980, the State Corporation Commission began developing a methodology for calculating avoided costs for use in establishing the required standardized avoided cost rates for small power generators. These standardized rates were approved for Virginia Power in its Schedule 19. *Implementation of Federal Rules concerning Cogeneration (and Small Power Production Facilities Pursuant to § 210 of the Public Utility) Regulatory Policies Act of 1978 for Virginia Electric and Power Company*, Case No. PUE800102, 1983 S.C.C. Ann. Rep. 345 (Jan. 11, 1983). From its inception, the methodology used for Schedule 19 rates included a component based on a utility's liability for gross receipts taxes (GRT). The methodology and rates have been periodically reviewed and refined but have always included the GRT factor.

In 1992, in a proceeding reviewing the Schedule 19 rates, the staff of the Commission concluded that including a GRT factor as part of the utility's avoided cost was in error. The utility's GRT liability could not be avoided by purchasing, rather than generating, electric power. These taxes would always be paid by the utility based on its gross revenues.

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[1]Standard rates may be used for purchases from generators with design capacities in excess of 100 kilowatts at the state's option. 18 C.F.R. § 292.304(c)(2) (1994). Virginia Power's Schedule 19 rates are applicable to purchases from non-utility generators with design capacity of up to 200 kilowatts.

Therefore, amounts included in the avoided cost calculation based on GRT were not, and could never be, properly included in the "avoided" or "incremental" cost as defined by federal law. Consequently, in the Commission's final order in that proceeding, the GRT portion of payments to non-utility generators was eliminated prospectively from Schedule 19 rates. *Application of Virginia Electric and Power Company*, Case No. PUE920060, 1993 S.C.C. Ann. Rep. 283 (Feb. 17, 1993).

In the present rate case, a GRT expense factor was identified in 58 electric power purchase contracts. The Commission staff recommended that the GRT expenses be allowed for such contracts only if the contract rate had been specifically approved by the Commission or the FERC or was governed by Schedule 19.[2] The Staff also indicated that disallowance would not be applicable to fully negotiated contracts in which no GRT component could be identified.

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[2]Virginia Power divided the contracts into 6 categories:

1. Generators with rates based on a non-differential revenue requirement Schedule 19 that was approved by the Commission prior to the adoption of the Avoided Cost Task Force Report in Case No. PUE870081 (Dec. 30, 1988).
2. Generators that agreed to the Schedule 19 type capacity rates adopted by the Commission.
3. Generators with rates approved by the FERC.
4. Generators that obtained contracts as a result of the 1986 Solicitation.
5. Generators whose rates were specifically ordered by the Commission in an arbitration.
6. Generators with rates based on Schedule 19 that were approved after the adoption of the Avoided Cost Task Force Report in Case No. PUE870081 (Dec. 30, 1988).

The staff recommended that the GRT expenses be disallowed for contracts in categories 2 and 4.

The hearing examiner acknowledged that the GRT expense was not an avoided cost, but rejected the staff's position and recommended that the GRT expense in all contracts be allowed for ratemaking purposes.

The Commission, after considering the hearing examiner's report and parties' comments on that report, held that GRT expenses were not an element of avoided cost and therefore were "unnecessary and excessive." The Commission disagreed with the hearing examiner's recommendation regarding disallowance of GRT expenses and adopted the staff's position. In its final order entered February 3, 1994, the Commission disallowed the GRT expenses for those contracts which were not specifically ordered or approved by the FERC or the Commission, but declined to "reduce an expense which the FERC or we have reviewed, approved and explicitly ordered."

Appeals were filed by Virginia Power and five non-utility power generators--Chesapeake Paper Products Company (Chesapeake), Hopewell Cogeneration Limited Partnership (HCLP), Enron-Richmond Power Corporation (Enron), Cogentrix Virginia Leasing Corporation (Cogentrix), and Appomattox Cogeneration Limited Partnership (ACLP).[3] The GRT expenses in the contracts between Virginia Power and these non-utility generators were within the group disallowed by the Commission. We consolidated the appeals for our review.

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[3]The Commission's disallowance affected expenses associated with payments to a total of 18 non-utility generators; only five are parties to this appeal.

None of the appellants asserts that the GRT is an appropriate element of avoided cost. The appellants variously argue that the disallowance was in violation of federal law, erroneous as a matter of law, arbitrary and capricious, an abuse of discretion, and not supported by the record. For the reasons expressed below, we will affirm the Commission's order.

I.

Virginia Power, Enron, Cogentrix, HCLP, and ACLP contend that PURPA and its regulations reflect a federal policy that precludes the Commission from focusing on and disallowing a single component of an avoided cost rate. Appellants argue that, when considering matters relating to an avoided cost rate, federal policy requires the Commission to analyze the rate in its entirety, to review all the data, estimates, and assumptions underlying the rate calculation, and then to redetermine the appropriate rate. Once that review is made, according to these appellants, only those amounts exceeding the redetermined rate can be deemed unreasonable and excessive and, therefore, subject to disallowance.

This argument is grounded on 18 C.F.R. § 292.304(b)(5) which allows the validity of the avoided cost rate to be determined based on relevant factors at the time the contract was executed rather than at the time the power is actually delivered. However, this provision does not support appellants' conclusion that once a contract is executed, the components of an avoided cost rate contained in that

contract are insulated from regulatory review in a rate setting proceeding.[4]

To adopt the appellants' interpretation would forever bar a regulatory commission from reviewing and rectifying clear and possibly egregious errors which, like the GRT expense here, could never constitute a cost that could be avoided by purchasing, rather than generating, power. To preclude the Commission from eliminating improper payments when engaged in its ratemaking function is inconsistent with PURPA's requirements that the avoided cost rate be just and reasonable to the consumer.

In fact, the Commission did not ignore this regulation, but distinguished its applicability in this proceeding. The Commission determined that the type of error addressed here was not the type of error envisioned under 18 C.F.R. § 292.304(b)(5); it did not result from imprecise estimates, changes in circumstances or assumptions, erroneous calculations, or refinement of a methodology. This error existed at the time the contracts were executed. The GRT expense was no more reasonable and valid at the time the contracts were executed than it is now. As stated by the Commission, "[w]e draw a sharp and distinguishing line between learning curve enhancements or refinements and

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[4]The non-utility generators anticipated the possibility of regulatory action impacting the avoided cost rates. For example, the Chesapeake contract states that "[s]hould the SCC at any time prohibit Vepco from recovering from its customers, payments, in whole or in part, made hereunder, the Parties will undertake to set mutually agreeable prices for the purchase of energy and capacity that will be allowed to be recovered from Vepco's customers." Each of the contracts at issue here contains a similar "regulatory out" provision.

pure error. . . . GRT inclusion is not a refinement of the avoided cost calculation."

Nothing in the language of PURPA or the regulations supports the appellants' view of the role of a state public utility commission in a ratemaking proceeding. In this case, the Commission was not considering whether an avoided cost rate contained in a purchased power contract complies with the requirements of PURPA or related federal and state regulations. *Cf. West Penn Power Co. v. Pennsylvania Pub. Util. Comm'n*, 623 A.2d 383 (Pa. 1993). In this case, the Commission was required to evaluate the reasonableness of an expense to determine whether that expense can properly be recovered from the utility's ratepayers. The principles applicable here are those relating to setting public utility rates and are well established under state law.

II.

Setting public utility rates is a legislative function. In exercising that function, the Commission is vested with a reasonable amount of discretion. *Old Dominion Power Co., Inc. v. State Corp. Comm'n*, 228 Va. 528, 532, 323 S.E.2d 123, 125 (1984). It is the utility's burden to show that the expenses it seeks to have included in its rate base are just and reasonable. Code § 56-235.3. If the Commission's determinations are supported by the record, there is no abuse of discretion and the Commission's decision should be affirmed. *Commonwealth v. Potomac Edison Co.*, 233 Va. 165, 171, 353 S.E.2d 785, 788-89 (1987).

Here, Virginia Power did not show that the expense it sought to recover as an element of its avoided cost

payments was just and reasonable.[5] There is no dispute that the GRT component is not an element of avoided cost. Clearly, including a GRT component in the avoided cost rate calculation makes the rate higher than it would have been without it. Therefore, the Commission was correct in holding that including the GRT expense is "unreasonable and unnecessary," regardless of the actual amount of the rate.

Nevertheless, appellants assert that the amounts paid them by Virginia Power for purchased power were reasonable and not subject to disallowance because they were below the utility's avoided cost as reflected in the Schedule 19 rates. Schedule 19 rates, however, are not applicable to the negotiated rates between Virginia Power and these non-utility generators. There is no single "avoided cost" for the utility applicable to all power purchases. Therefore, comparison of the payments made with the relevant Schedule 19 rates is not probative of either the utility's avoided cost for the purchases from these specific non-utility generators or the reasonableness of the expenses incurred under individually negotiated contracts.

In summary, there is nothing in the record to support the proposition that the inclusion of the gross receipts tax component within the amounts paid for purchased power was reasonable. To the contrary, the record supports the

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[5]The Commission's decision to disallow the GRT expense in the avoided cost rates does not preclude Virginia Power from recovering its gross receipts tax expenses from its ratepayers. The total GRT paid by Virginia Power was allowed as an operating expense. It is only the second recovery of the GRT expense as an element of avoided cost expense that was disallowed.

Commission's decision that the expenses based on gross receipts taxes were unnecessary and excessive and, therefore, the Commission's decision to disallow those expenses was not an abuse of discretion. *Lake of the Woods Utility Co. v. State Corp. Comm'n*, 223 Va. 100, 110, 286 S.E.2d 201, 206 (1982); *City of Norfolk v. Chesapeake & Potomac Tel. Co.*, 192 Va. 292, 304-05, 64 S.E.2d 772, 779 (1951).

III.

Virginia Power, HCLP, Enron, Cogentrix, and ACLP also challenge the Commission's decision to disallow the GRT factor expense for some, but not all, of the 58 affected purchase power contracts.

The Commission determined that it would be inequitable to deny recovery of the expenses in question where the Commission or the FERC had specifically approved or required the rate. Thus, the Commission disallowed the GRT expense only in those instances in which the contract rates were not subject to Schedule 19 or had not been specifically approved by the FERC or the Commission.

These appellants agree that it would be inequitable to disallow the gross receipts tax expense where the contract rates had been specifically approved by the Commission or the rate was required by Schedule 19. They also recognize that, under the filed rate doctrine, the Commission was required to accept expenses associated with the FERC approved rates. *See Nantahala Power and Light Co. v. Thornburg*, 476 U.S. 953 (1986). Nevertheless, they argue that the Commission could not discriminate in their treatment of the GRT expense and, even if such

discrimination was permissible, the Commission erred in disallowing the expense in their contracts because they were based on the same considerations as those contracts in which the expense was allowed. Again, we disagree.

In exercising its ratemaking authority, the Commission has the authority to establish classifications. As long as the classifications are not based on race, gender, religion, or other "suspect" criteria, they "will be upheld if they bear some rational relationship to a legitimate interest or purpose." *Old Dominion*, 228 Va. at 534, 323 S.E.2d at 126-27. Here the Commission recognized two classes of power purchase contracts: (1) those governed by Schedule 19 or previously approved by the Commission or the FERC; and (2) those neither governed by Schedule 19 nor approved by the Commission or the FERC. The specific prior approval of an expense is a legitimate distinction between these two classifications and bears a rational relationship to the ratemaking undertaking at issue. Therefore, the action of the Commission in treating the two classifications in different ways for purposes of the GRT expense recovery was not arbitrary or capricious or an abuse of discretion.

We also reject the argument that the contracts of these non-utility generators are entitled to the same ratemaking treatment as those contracts for which the GRT expense was allowed because of similarities in their avoided cost methodologies. Cogentrix and Enron argue, respectively, that the rates in their contracts were based on Schedule 19 rates and a bidding solicitations methodology ultimately approved by the FERC. Therefore, they assert, they were entitled to the same treatment as contracts approved by the FERC or subject to Schedule 19 rates. However, although Cogentrix and Enron may have chosen to model their

contract negotiations after these factors, they were under no obligation to do so. Negotiations based on previously approved Schedule 19 rates or rates below those approved in other proceedings do not transform these contracts or their rates into ones specifically approved by the Commission or by the FERC. The Commission's determination that the avoided cost rates in these contracts lacked prior specific approval is supported by the record and, therefore, was not an abuse of discretion.

IV.

ACLP argues that its contract was specifically approved by the Commission in an arbitration proceeding between its predecessor and Virginia Power. Thus, it also asserts that its contract should be classified with those in which the GRT expense was allowed. The final order in the arbitration proceeding, however, recites that the arbitration addressed two issues:

> the effective date of a contract between [ACLP's predecessor] and Vepco for the purchase of electricity generated by [ACLP's predecessor] and sold to Vepco and whether [ACLP's predecessor] is entitled to a credit from Vepco for alleged avoided interconnection costs associated with [ACLP's predecessor's] qualifying facility.

Arbitration Proceeding Between Continental Forest Industries, Inc. and Virginia Electric and Power Company, Case No. PUE820052, 1983 S.C.C. Ann. Rep. 367 (Feb. 2, 1983). Accordingly, we conclude that the Commission did not err in determining that the arbitration proceeding did not approve the avoided cost rate contained in the contract.

V.

Finally, HCLP and Chesapeake contend that the evidence is insufficient to support a finding that their contracts were based on or included a gross receipts tax component. HCLP's avoided cost rate is a "blended rate," that is, a weighted average rate based on the cost of the avoided Chesterfield 7 plant for both a 300 MW and 356.5 MW facility. Two witnesses testified, however, that a GRT component was included within the calculations and subsequent payments to HCLP. Virginia Power acknowledged that a GRT factor was included in establishing rates based on the cost of the Chesterfield 7 facility.

Similarly, Chesapeake asserts that there was no evidence to show that a GRT expense was within the avoided cost rate it negotiated with Virginia Power. Although there is no specific evidence which details the various components of the negotiated avoided cost rate in Chesapeake's contract, there was testimony that the negotiations began by utilizing the methodology adopted for Schedule 19 rates, a methodology which contained the GRT expense factor.

Applying the standards outlined above for review of the Commission's actions in utility rate cases, we conclude that the record supports the Commission's determination that a GRT factor was included in the contract rates Virginia Power negotiated with both HCLP and Chesapeake.

In summary, for the reasons stated above, we find that the decision of the Commission to disallow Virginia Power's recovery of GRT expenses contained in purchased power contracts with HCLP, Enron, Cogentrix, Chesapeake, and

ACLP did not violate federal law, was supported by the evidence, and was not arbitrary or capricious or an abuse of discretion. Accordingly, we will affirm the order of the Commission.

Affirmed.

VIRGINIA:

In the Supreme Court of Virginia held at the Supreme Court Building in the City of Richmond on Friday *the* 13th *day of* January, 1995.

Hopewell Cogeneration Limited Partnership, Appellant,

against Record No. 940885
S.C.C. Case No. PUE920041

State Corporation Commission, Appellee.

Upon an appeal of right from an order entered by the State Corporation Commission on the 3rd day of February, 1994.

For reasons stated in writing and filed with the record, the Court is of opinion that there is no error in the order appealed from. Accordingly, the order is affirmed. The appellant shall pay to the appellee thirty dollars damages.

This order shall be certified to the State Corporation Commission.

A Copy,

Teste:

/s/ David B. Beach
Clerk

VIRGINIA:

In the Supreme Court of Virginia held at the Supreme Court Building in the City of Richmond on Friday *the* 13th *day of* January, 1995.

Enron-Richmond Power Corp., Appellant,

against Record No. 940886
S.C.C. Case No. PUE920041

State Corporation Commission, Appellee.

Upon an appeal of right from an order entered by the State Corporation Commission on the 3rd day of February, 1994.

For reasons stated in writing and filed with the record, the Court is of opinion that there is no error in the order appealed from. Accordingly, the order is affirmed. The appellant shall pay to the appellee thirty dollars damages.

This order shall be certified to the State Corporation Commission.

A Copy,

Teste:

/s/ David B. Beach
Clerk

VIRGINIA:

In the Supreme Court of Virginia held at the Supreme Court Building in the City of Richmond on Friday *the* 13th *day of* January, 1995.

Cogentrix Virginia Leasing Corp., Appellant,

against Record No. 940887
S.C.C. Case No. PUE920041

State Corporation Commission, Appellee.

Upon an appeal of right from an order entered by the State Corporation Commission on the 3rd day of February, 1994.

For reasons stated in writing and filed with the record, the Court is of opinion that there is no error in the order appealed from. Accordingly, the order is affirmed. The appellant shall pay to the appellee thirty dollars damages.

This order shall be certified to the State Corporation Commission.

A Copy,

Teste:

/s/ David B. Beach
Clerk

VIRGINIA:

In the Supreme Court of Virginia held at the Supreme Court Building in the City of Richmond on Friday *the* 13th *day of* January, 1995.

Appomattox Cogeneration Limited Partnership, Appellant,

against Record No. 940888
S.C.C. Case No. PUE920041

State Corporation Commission, Appellee.

Upon an appeal of right from an order entered by the State Corporation Commission on the 3rd day of February, 1994.

For reasons stated in writing and filed with the record, the Court is of opinion that there is no error in the order appealed from. Accordingly, the order is affirmed. The appellant shall pay to the appellee thirty dollars damages.

This order shall be certified to the State Corporation Commission.

A Copy,

Teste:

/s/ David B. Beach
Clerk

VIRGINIA:

In the Supreme Court of Virginia held at the Supreme Court Building in the City of Richmond on Friday *the* 3rd *day of* March, 1995.

Hopewell Cogeneration Limited Partnership, et al., Appellants,

against Record Nos. 940885, 940886, 940887 and 940888
S.C.C. Case No. PUE920041

State Corporation Commission, Appellee.

Upon a Petition for Rehearing

On consideration of the petition of the appellants to set aside the judgments rendered herein on the 13th day of January, 1995 and grant a rehearing thereof, the prayer of the said petition is denied.

A Copy,

Teste:

/s/ David B. Beach
Clerk

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION

APPLICATION OF

VIRGINIA ELECTRIC AND POWER COMPANY

CASE NO. PUE920041
Phase III

For a general increase in rates
October 27, 1993

FINAL REPORT OF RUSSELL W. CUNNINGHAM

SENIOR HEARING EXAMINER

On May 29, 1992, Virginia Electric and Power Company ("Virginia Power" or "Company") filed an application for an increase in its rates. By order dated September 30, 1992, the Commission set the application for hearing and established a procedural schedule.

Pursuant to a Hearing Examiner's Ruling dated January 14, 1993, public witnesses were heard on March 8, 1993. Eight public witnesses testified against the Staff proposal to exclude gross receipts tax from Company's recoverable payments to certain qualifying facilities. This issue was bifurcated from the revenue requirement (Phase I) into a separate phase (Phase III) by Hearing Examiner's Ruling dated March 16, 1993. A hearing was scheduled for September 8, 1993, and a procedural schedule was established by Hearing Examiner's Ruling dated June 25, 1993. This Ruling also directed Virginia Power to provide

notice to all persons under contract with the Company who might be affected by this issue.

Counsel appearing at the hearing were Pamela Johnson and Richard D. Gary for the Company; Charles H. Tenser, III, for Virginia Hydro Power Association ("Virginia Hydro"); Edward L. Flippen for Chesapeake Paper Products Company ("Chesapeake Paper"); Stephen H. Watts, II, and Mark J. LaFratta for Hopewell Cogeneration Limited Partnership, Appomattox Cogeneration Limited Partnership, Cogentrix Virginia Leasing Corporation, and Enron-Richmond Power Corp. ("ACLP/HCLP"); Eric M. Page and Marjorie Philips for Union Camp Corporation ("Union Camp"); Philip F. Abraham for Browning-Ferris Gas Services, Inc. and Richmond Electric Generation Facility ("Browning"); Laurence M. Hamric for Doswell Limited Partnership ("Doswell"); Edward L. Petrini for the Office of Attorney General, Division of Consumer Counsel; and Deborah V. Ellenberg and Judith W. Jagdmann, counsel to the Commission.

Counsel agreed to introduce all of the prefiled testimony into the record without cross-examination.

Company presented the testimony of four witnesses: Larry W. Ellis, Daniel J. Green, James P. Carney, and Jeffrey L. Jones. Company offered three witnesses in rebuttal: Larry W. Ellis, Daniel J. Green, and Jeffrey L. Jones.

Staff offered the testimony of one witness, Thomas E. Lamm.

Virginia Hydro presented the testimony of one witness, John K. Pollock. Chesapeake Paper offered the testimony of one witness, Desi W. Gully. ACLP/HCLP presented the testimony of two witnesses: Roy J. Shanker and William P. Utt. Union Camp offered the testimony of one witness, Edward C. Minor.

Post-hearing briefs were filed by the parties on October 8, 1993.

A federal law, PURPA, administered by this Commission, requires Virginia Power to buy electricity from certain non-utility generators (NUGs). The rate at which the Company pays for that power is based on its avoided cost.

The calculation of avoided cost is based on thousands of factors and assumptions. Over time, many factors have been modified, increased, decreased, eliminated, and added. For small NUGs, the Commission itself establishes the avoided cost, in Schedule 19 proceedings. Other, larger NUGs pay on the basis of arms-length bargaining with the utility. The resulting contracts are filed with the Commission, but none have been formally reviewed and approved. A few have a power rate that was established by arbitration.

In an earlier case, Case No. PUE920060, Staff discovered an inadvertent error in the Company's avoided capacity cost calculation which served as the basis for determining capacity payments to certain qualifying facilities. The Company had included gross receipts tax ("GRT") in the calculation of avoided costs, yet GRT is not avoided when the utility purchases power. In that case the Company admitted its error and in the Final Order dated February 17,

1993, the Commission concluded that such an error had indeed been made and should be corrected. The Commission thus directed the elimination of the GRT component from the calculation of the Schedule 19 rate approved in that case.

In the pending case, Staff asserts that gross receipts taxes were also erroneously included in the avoided cost calculation used to determine some payments included in the Company's going level of capacity. There is no dispute that a GRT element was included in the original and subsequent Schedule 19 rates. The Company and protestants agree that GRT should be excluded from future contracts. However, Staff proposed -- originally -- that a GRT cost should be developed for every NUG participant, and the total amount deducted from Virginia Power's cost of service.

Staff acknowledged that that might result in contractual disputes between Virginia Power and the NUGs, but argues that is not an issue here; the sole issue, claims Staff, is the level of expense that ratepayer must pay, not the indirect implications of a disallowance on the supplier contract.

Staff's concept would have reduced payments to fifty-eight (58) NUGs, of approximately $4.2 million. Subsequently, the NUGs were separated into the following six categories:

I. NUGs with rates based on a Non-Differential Revenue Requirement Schedule 19 that was approved by the Commission prior to the adoption of the Avoided Cost Task Force Report -- Case NO. PUE870081 (December 30, 1988).

II. NUGs that agreed to the Schedule 19-type capacity rates adopted by the Commission.

III. NUGs with rates approved by the Federal Energy Regulatory Commission.

IV. NUGs with contracts based on Chesterfield Unit 7 costs.

V. NUGs whose rates were specifically ordered by the Commission in an Arbitration.

VI. Schedule 19-approved after adoption of the Tax Force Report.

By the close of the hearing and briefing, Staff had modified its position, excluding from its disallowance proposal the following: (1) facilities operating under "standard offer" Schedule 19 contracts with Commission approved payment schedules (Categories I and VI), (2) contracts with payment schedules approved by the Commission as a result of arbitration proceedings (Category V) and (3) contracts with payment schedules approved by the FERC (Category III). The Staff also does not object to exclusion of capacity payments classified by Virginia Power as "negotiated capacity prices" for which there is "no separately identifiable GRT component in the calculation of the capacity rates."

According to the Staff, a GRT component of capacity payments should be disallowed only for: (1) non-utility generators ("NUGs") that agreed to "Schedule 19-type" capacity rates adopted by the Commission before the adoption of the Task Force Report on the Differential

Revenue Requirement ("DRR") (Category II) and (2) QF NUGs that obtained contracts as a result of the 1986 Solicitation (Category IV).

As a result, only 18 NUGs remain on Staff's disallowance list, with about $2 million at issue. The rationale for excluding most of the NUGs was stated by Staff witness Lamm:

> Staff believes disallowance for the GRT embedded in capacity expense of all affected facilities is justifiable from the perspective of ratepayers. However, Staff also recognizes the importance of stability as regards Commission approved payment schedules. Considering the particular circumstances in this case, Staff believes a balancing of these interests can best be achieved by exempting from disallowance the capacity expense associated with facilities having contracted payment schedules which were *specifically and explicitly arbitrated, ordered and/or approved by this Commission or FERC.* (Emphasis added.)

On brief, Staff argues that it "would not be fair for the Commission to reduce an expense which it had reviewed, approved, and explicitly ordered." Staff continued to assert, however, that capacity expenses for those facilities with contract payment schedules which have not been specifically and explicitly approved by the Commission or FERC, should be disallowed.

Everyone, including Staff, agrees that the inclusion of GRT in the calculation of avoided cost was wrong, regardless of whether inclusion was by "error" or otherwise.

Everyone, including Staff, agrees that future contracts should exclude any GRT element and that there should be no retroactive treatment for existing NUG agreements.

Historically, this Commission took the lead in the development of avoided cost. It required all electric utilities to file a standard agreement, including the cost or rate to be paid by the utility to a NUG, for the power it purchased. The agreement would apply, however, only to the smaller producers -- say 800 kW or less. A power producer exceeding that amount would have to negotiate its own agreement, and rate, with the utility.

When the Commission approved the provisions of the agreement, it also approved the rate of payment (the Schedule 19). That rate was a clear message to the negotiators of the utility and the larger producers. Schedule 19 became the benchmark for the negotiators. It also became a glass ceiling -- to negotiate a rate above the Schedule 19 rate would be most difficult for the NUG.

In addition, the utility would often press for non-rate advantages. As a trade-off, some NUGs accepted a rate below the Commission approved rate. The result was a negotiated rate without an identifiable GRT component. (See the testimony of Chesapeake Paper's Gulley, and ACLP/HCLP's Utt and Shanker.)

Thus, in every case, a NUGs rate was determined by the Commission, either directly or indirectly, I see no rational basis to split this "baby". Either every NUG rate should reflect a disallowance for GRT, or none should be affected. If the Commission rate contains a minuscule error, all rates are so infected. It would be wrong for the Commission to

shelter the error in its own rates (Schedule 19), while reducing rates for NUGs outside of Commission orders.

I agree with Staff that "it would not be fair for the Commission to reduce an expense which it has... ordered." But fairness is a two-way street. It would be equally unjust, unfair, and arbitrary to penalize someone who also had relied upon those Commission orders.

Finally, the ratepaying customers will not be adversely affected. The rate effect of -- at -- $2 million on a Company with annual revenues of over $3.3 billion is unmeasurable.

It is for these reasons that I find that the Staff GRT adjustment should not be accepted. By no means should the "error" go unrecognized. Staff's pursuit of that factor underscores its performance in the role of *defensor civitatis* for the ratepayer. However, I further find that the elimination of the GRT element from future agreements and Schedule 19s is a sufficient remedy.

COMMENTS

The parties are advised that any comments (Rule 5:15(e)) to this Report must be filed with the Clerk of the Commission in writing, in an original and fifteen (15) copies, within fifteen (15) days from the date hereof. The mailing address to which any such filing must be sent is Document Control Center, P.O. Box 2118, Richmond, Virginia 23216. Any party filing such comments shall attach a certificate to the foot of such document that copies have been mailed or delivered to all other counsel of record and to any party not represented by counsel.

Respectfully submitted,

/s/Russell W. Cunningham
Russell W. Cunningham
Senior Hearing Examiner

Document Control is requested to mail or deliver a copy of the above Report on October 27, 1993 to: Kendrick R. Riggs, Esquire, 1200 One River Front Plaza, Louisville, KY 40202; Evans B. Brasfield, Esquire, 951 East Byrd St., Riverfront Plaza - East Tower, Richmond, VA 23219-4074; Edward L. Petrini, Office of the Attorney General, Division of Consumer Counsel, 101 North 8th St., 6th Fl., Richmond, VA 23219; Stanley Balis, Esquire, 1001 14th St., NW, #1400, Washington, DC 20005; Dennis R. Bates, Esquire, and Kyle Elizabeth Skopic, Esquire, 12000 Government Center Parkway, Suite 549, Fairfax, VA 22035-0064; Denise Waters Bland, Esquire, P.O. Box 8795, Williamsburg, VA 23187; Steven Bruack, Esquire, 785 Washington St., Canton, MA 02021; Edward L. Flippen, Esquire, P.O. Box 1122, Richmond, VA 23208-1122; Fran G. Francis, Esquire, 1050 17th St., NW, Suite 300, Washington, DC 20036; Donald R. Hayes, Esquire, 1100 H St., NW, Washington, DC 20080; Laurence M. Hamric, Esquire, 1021 East Cary Street, Richmond, VA 23210-1320; David B. Kearney, 900 E. Broad St., Suite 300, Richmond, VA 23219; Pamela Johnson, Esquire, P.O. Box 2666, Richmond, VA 23261; Louis R. Monacell, Esquire, 1200 Mutual Building, Richmond, VA 23219-3095; Eric M. Page, Esquire, 316 West Broad St., Richmond, VA 23220-4257; T. Randolph Perkins, Esquire, 9405 Arrow Point Blvd., Charlotte, NC 28217; Marjorie R. Philips, Esquire, 300 South Grand Ave., Los Angeles, CA 90071; Oliver A. Pollard, III, Esquire, 201 West Main St., #14, Charlottesville, VA 22901; Frederick H. Ritts, Esquire, Julie B. Greenison, Esquire, and Garrett A. Stone, Esquire, 1025 Thomas Jefferson St., NW, Washington, DC 20007; Charles H. Tenser, Esquire, P.O. Box 1122, Richmond, VA 23208-1122; Stephen H. Watts, II, Esquire, One James Center, Richmond, VA 23219-4030; James Cotton, 38-C Grove St., Ridgefield, CT 06877; Ms.

Jean Ann Fox, 114 Coachman Drive, Yorktown, VA 23693; J. B. Hall, Jr., 1108 E. Main St., Richmond, VA 23219; Philip F. Abraham, P.O. Box 788, Richmond, VA 23206; Mark J. La Fratta, Esquire, 1 James Center, Richmond, VA 23219-4030; Deborah V. Ellenberg, Esquire, Commission counsel; and to the Commission's Divisions of Public Utility Accounting, Economics and Finance, and Energy Regulation.

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION
AT RICHMOND, FEBRUARY 3, 1994

APPLICATION OF
VIRGINIA ELECTRIC AND POWER COMPANY
CASE NO. PUE920041

For a general increase in rates

FINAL ORDER

On May 29, 1992, Virginia Electric and Power Company ("Virginia Power" or the "Company") filed an application for a general increase in rates designed to produce total annual operating revenue of $3,362,002,000 based on a test year ending December 31, 1991. That proposed revenue requirement was an increase in annual operating revenues of $165,864,000 over the level of revenues being collected on an interim basis through the rates in effect at the time the application was filed. At the time of the application, the Company's previous rate case, Case No. PUE910047, was still pending.

The Commission issued its final order in that case on December 29, 1992. The Company had sought an increase of $184 million, however, the Commission approved an increase in additional gross revenues of only $45 million annually effective for service rendered from September 1, 1991 through October 26, 1992. That amount was significantly lower than the interim revenue generated at the time the application in this case was filed; accordingly, the additional revenue necessary to reach the $3.362 billion

level sought by this application increased from $165.9 million to $314,633,000.

On June 17, 1992, the Commission suspended the proposed rates through October 26, 1992. On October 13, 1992, Jean Ann Fox filed a pro se motion to dismiss the application alleging that it did not comply with the Commission's rate case rules. That motion was denied by hearing examiner ruling dated October 26, 1992. By further ruling the Examiner allowed interim rates to be placed into effect, under bond and subject to refund with interest, for service rendered on and after October 27, 1992.

On March 8, 1993, a public hearing was convened for the sole purpose of receiving comments from public witnesses and interveners. The hearing was reconvened on March 22, 1993. Due to the unusually large number of parties in this case, the hearing process was divided into three phases with the first phase focused on all issues except the Company's proposed line extension policy, summer/winter differential rate design and a gross receipts tax issue raised by Staff. Thus, Phase I addressed the appropriate aggregate revenue requirement for Virginia Power, allocation of the resulting increase and all but one rate design issue. Counsel appearing in Phase I were Evans B. Brasfield, Richard D. Gary, Kendrick R. Riggs and Pamela Johnson for the Company; Deborah V. Ellenberg and Robert M. Gillespie for the Commission Staff; Edward L. Petrini for the Office of the Attorney General, Division of Consumer Counsel ("Consumer Counsel"); James C. Dimitri and Louis R. Monacell for the Virginia Committee for Fair Utility Rates ("Virginia Committee"); Dennis R. Bates and Kyle Elizabeth Skopic for Fairfax County; third year law students, Thomas M. Browder, III, Lance W. High and Scott A. Shefferman,

with supervising attorney Denise W. Bland for the Virginia Citizen Consumer Council ("VCCC"); Frann G. Francis and Vernon E. Inge for the Apartment and Office Building Association of Metropolitan Washington ("AOBA"); Garrett A. Stone and Julie B. Greenisen for Philip Morris; and Richard A. Parrish, Jeffrey M. Gleason, and Oliver A. Pollard, III for the Southern Environmental Law Center ("SELC").

Phase II focused exclusively on the Company's proposed new line extension policy and summer/winter differential changes and was convened on March 30. Counsel appearing in Phase ll were Evans B. Brasfield, Richard D. Gary, Kendrick R. Riggs and Pamela Johnson for the Company; Deborah V. Ellenberg and Robert M. Gillespie for the Commission Staff; Richard A. Parrish, Jeffrey M. Gleason and Oliver A. Pollard, III for the SELC; Charles H. Tenser and Donald A. Fickenscher for Virginia Natural Gas, Inc. ("VNG"); Eric M. Page for the Home Builders Association of Virginia ("HBA"); Edward L. Flippen for the Sierra Club; David B. Kearney and Stanley W. Balis for the City of Richmond; and Donald R. Hayes and Karen B. Pancost for Washington Gas Light Company ("WGL").

Phase III was commenced on September 8, 1993 to address Staff's recommendation to disallow a portion of the Company's capacity costs, specifically, a portion resulting from the inclusion of gross receipts tax in the calculation of avoided costs. Counsel appearing in Phase III were Richard D. Gary and Pamela Johnson for the Company; Deborah V. Ellenberg and Judith W. Jagdmann for the Commission Staff; Edward L. Petrini for the Consumer Counsel; Charles H. Tenser, III for the Virginia Hydro Power Association; Edward L. Flippen for Chesapeake Paper Products

Company; Mark J. LaFratta and Stephen H. Watts, II for Appomattox Cogeneration Limited Partnership, Hopewell Cogeneration Limited Partnership, Cogentrix Virginia Leasing Corporation and Enron-Richmond Power Corporation; Eric M. Page and Marjorie Philips for Union Camp Corporation; Phillip F. Abraham for Browning-Ferris Gas Services, Inc. and Richmond Electric Generation Facility; and Laurence M. Hamric for Doswell Limited Partnership.

On September 3, 1993, Russell W. Cunningham, Senior Hearing Examiner, issued his Report on Phase I in which he discussed the many issues raised in this portion of the proceeding and his recommendations for resolution. The Examiner found that based on the evidence received in this case:

1. The use of a test year ending December 31, 1991, is proper in this proceeding;

2. The Company's test year operating revenues, after all adjustments, were $3,010,793,000;

3. The Company's test year operating revenue deductions, after all adjustments, were $2,525,713,000;

4. The Company's test year adjusted net operating income was $485,080,000;

5. The Company's current rates produce a return on adjusted rate base of 6.95% and a return on equity of 6.25%;

6. Based on the Company's capital structure as of December 31, 1992, the Company's overall cost of capital is 9.123%;

7. The Company's adjusted test year rate base is $6,972,009,000;

8. The Company's application requesting $314,633,000 is unjust and unreasonable because it will generate a return on rate base greater than 9.123%; and

9. The Company requires $234,796,000 in additional gross annual revenues to earn 9.123% return on rate base.

The Examiner recommended continuing deferred accounting for non-utility capacity costs, incorporating a rate year going level of capacity costs and including a portion of the capacity deferral balance at October 26, 1992. However, he recommended disallowing the carrying costs incurred on that capacity deferral through October 26, 1992. He recommended disallowing a portion of Company's incentive compensation, including the funded accrual of other post-employment benefit ("OPEB") costs and updating rate base beyond the test year. He also addressed numerous other accounting issues. He found 10.5% to 11.5 % was a reasonable range for the Company's cost of capital. The Examiner recommended the Commission retain the average and excess cost allocation methodology for Virginia Power and addressed several rate design issues related to the new GS-l through GS-4 rate classifications. The Examiner recommended that the Commission enter an order adopting his findings and conclusions, authorizing rates to produce the additional revenue requirement and directing the appropriate refund to the customers.

Comments and exceptions to the Hearing Examiner's Report on Phase I were filed on October 1, 1993. Virginia Power took exception to the Hearing Examiner's recommendation to disallow $1.6 million of carrying costs on deferred capacity. It also took exception to the Examiner's recommendation to disallow budget incentives, his decision to retain the capital structure method of calculating interest synchronization, his finding that ratepayers should be refunded $1.1 million in life insurance premium credits, and his recommendations on calculating revenue lag for purposes of determining the allowed cash working capital. The Company recommended 11.25-12.25% as a reasonable range for its cost of capital and argued in support of a flotation adjustment.

The Consumer Counsel also filed exceptions to the Examiner's Phase I Report and took exception to the Examiner's recommendation to continue deferred accounting for capacity costs, treatment of the capacity deferral at October 26, 1992 and calculation of the going level of capacity. He further took issue with the Examiner's recommendations on incentive compensation, OPEB, interest on tax deficiencies, tax depreciation cushion, the calculation of the effective tax rate, determination of the appropriate capital structure, and the recommended return on equity range. The Consumer Counsel recommended 10-11 % as a reasonable return on equity. The Virginia Committee took exception to the Examiner's recommendation on the continuation of deferred accounting for capacity costs, recovery of the capacity deferral at October 26, 1992 and use of an updated rate base. The Virginia Committee also commented on revenue requirement allocation and rate design. VCCC excepted to the Examiner's recommendations on a portion of the Company's incentive compensation plan,

his return on equity range recommendation (VCCC recommended 10-11%), his recommendations on cost allocation methodology and the increase in the residential customer charge. The AOBA also filed exceptions commenting on the Examiner's recommended distribution of the revenue requirement. Philip Morris took exception to the Examiner's recommendations related to the GS-3 and GS-4 rate structure and designs and the GS-4 transmission discount. Fairfax County took exception to the Examiner's recommendation for an appropriate return on equity range, recommending instead the Commission approve 10-11%.

The Hearing Examiner issued his report on Phase II of this case on October 22, 1993. He recommended the Commission reject the Company's line extension plan. The Examiner also recommended the Commission reject the Company's proposal to increase the differential between the summer and winter rate tail blocks applicable to residential usage. The Company took exception with the Examiner's recommendation to reject both the line extension plan and the proposed increase in the summer/winter differential. All other participants in Phase II, including VNG, the City of Richmond, Sierra Club, WGL, SELC, and HBA, supported the Examiner's recommendations.

The Examiner issued his Report on the final phase of this proceeding on October 27, 1993. Therein the Examiner recommended that the Commission reject the Staff's proposal to disallow a certain portion of capacity costs resulting from the erroneous inclusion of gross receipts tax in the calculation of certain contracted capacity payments. Virginia Power and all Protestants involved in Phase III supported the Examiner's recommendations in comments filed to that report.

NOW, THE COMMISSION, upon consideration of the record, the Examiner's Reports, the exceptions thereto and the applicable statutes, is of the opinion and finds that the findings and recommendations contained in the September 3, 1993 Examiner's Report are, as modified herein, supported by the record. We differ from the Hearing Examiner only on the interest synchronization adjustment, the proper bonus for the Company's generating unit performance and consideration of expanding the performance incentive to include the Company's purchased power efforts. We also differ slightly on the proper allocation of the rate increase approved herein. We find that the recommendations contained in the October 22, 1993 Examiner's Report on Phase II are similarly supported by the record and should be adopted. We also find that a disallowance for the capacity costs attributable to the erroneous inclusion of gross receipts tax in the avoided cost calculation of certain non-utility generation purchased power contracts, as addressed in Phase III, is proper and in the public interest.

Senior Hearing Examiner Cunningham wrote these final reports before his retirement with the same flair and style characteristic of his work during his career as hearing examiner for the State Corporation Commission. Since the Examiner has fully discussed the issues raised in this proceeding, we will limit our discussion here to those issues upon which we reach a different finding than the Examiner and several of his recommendations on which parties take exception and which warrant further comment.

PHASE I

CAPACITY COSTS - DEFERRED ACCOUNTING

As the Hearing Examiner observed, capacity expenses related to purchased power represent the largest component of the proposed increase and account for the greatest spread in the revenue requirement recommendations advanced by the parties. No party in this case has questioned the reasonableness of the Company's purchased power costs; however, Consumer Counsel and the Virginia Committee took issue with the continued use of deferred accounting for those costs. The Virginia Committee seeks a phasing out of deferred accounting. It argues that the initiation of deferred accounting for those capacity costs resulted from unique circumstances in the 1991 case but that there is no permanent need for it in the future. In the Commission's Final Order in Virginia Power's last case, Case No. PUE910047, we concluded that memorandum accounting for purchased power costs was simply not working in the manner we had contemplated. We therefore decided to implement deferred accounting and discontinue the use of an earnings test to determine the rate treatment of account balances. Deferred accounting allows a straight forward true-up of under or overcollections of account balances. With such treatment we can ensure dollar-for-dollar recovery of reasonably incurred capacity costs. Although we agree that any extraordinary ratemaking adjustment should be evaluated in light of changing circumstances, deferred accounting for Virginia Power's purchased costs was only implemented in the last case and we will retain it here in light of the fact that purchased capacity costs continue to grow at a significant rate. For example, system purchased

capacity costs increased $185,437,000 from 1991 to 1992 or 69.7% and were projected to increase $139,578,000 from 1992 to 1993 or 30.9%. When the year to year differences decrease to a less significant level we will review again whether to continue this ratemaking treatment.

CAPACITY COSTS - GOING LEVEL

The Hearing Examiner recommended inclusion of a rate year level of capacity costs for all non-utility generation projects expected to be on line during the rate year. The Company provided supplemental testimony at the hearing to reflect February 1993 actual capacity expenses which the Examiner incorporated into his rate year level of costs. The Examiner also supported Staff's recommendation to include an offset for the rate year level of the off-system sales to Old Dominion Electric Cooperative and Santee Cooper which became effective January 1, 1993 and for projected sales growth to the end of the rate year. The Consumer Counsel, however, recommended incorporating a rate year level of the pro forma projects in base rates and deferring the rate year costs and revenues. Although only a pro forma level of capacity costs was allowed in the last case due to limitations imposed on expedited rate cases, we found that the public interest would be better served by the Company recovering prudently incurred capacity costs on a current basis. *Application of Virginia Electric and Power Company*, Case No. PUE910047, 1992 S.C.C. Ann. Rept. 291.

Except when the rate case rules prohibit use of a rate year level, we continue to believe that, even with deferred accounting, current cost recovery is in the ratepayer's best interest. We adopt the Hearing Examiner's recommendation to reflect a rate year level of capacity costs using February

1993 actual costs offset by off-system sales revenues and rate year sales growth.

CAPACITY DEFERRAL AT OCTOBER 26, 1992

As already noted, the Commission established deferred accounting in Case No. PUE910047. Therein, we directed the Company to implement the account effective January 1, 1990, the beginning of the test year in that case. The new rates in that case were effective September, 1991, and reflected only a pro forma level of capacity costs because that case was an expedited proceeding. The deferral balance at the end of the rate year in that case, October 26, 1992, grew to over $100 million.

Significant controversy arose in this case on how to treat that October 26,1992 deferred balance. The Consumer Counsel proposed including the deferred balance at the end of the 1991 test year in base rates, approximately $2 million, and leaving the remaining balance at October 26, 1992, in the deferred account and recorded in rate base. As an alternative, he recommended the Company be allowed to amortize the remaining balance over a three-year period, thus mitigating the impact of inclusion of the unrecovered capacity costs. The Virginia Committee also proposed that only the underrecovery of $2 million at the end of the test year be included in rates but recommended the deferred balance at October 26, 1992 be excluded from rate base and considered in a future case.

The Hearing Examiner recommended the Commission accept the Staff proposal to recover $64 million of the approximately $100 million in the current case. Staff projected that under such a proposal the deferral balance

would shrink from just over $100 million to approximately $28 million at the end of 1993 and zero out by mid-1994.

Regardless of the level of capacity costs built into base rates, the deferral will capture any over or underrecovery, but we want to guard against a large overcollection of purchased power capacity costs and minimize carrying costs associated with delaying recovery to a future period. We also want to balance the speed of recovery of the deferred costs with rate stability. We agree with the Examiner that Staff's proposal will best avoid an early overrecovery and a multi-year underrecovery with claims for carrying costs.

CARRYING COSTS OF DEFERRED CAPACITY BALANCE

While allowing recovery of the deferred balance, the Examiner disallowed $1.6 million of past carrying costs which the Company incurred from the delay in recovery of those deferred capacity charges through October 26, 1992. The Examiner found these past carrying costs to be non-recurring expenses and disallowed them. Virginia Power asserted that the Company should be allowed to recover carrying costs which it incurred as a result of having the recovery of capacity charges postponed from Case No. PUE910047 to this case. In support of its request, the Company relies on the Commission's order in that case and alleges that it authorizes the carrying costs to be passed on to customers. We agree with the Examiner that carrying costs associated with the deferred balance from January 1, 1990 to October 26, 1992, should be disallowed. Our Order in the last case did not authorize these costs to be passed on to ratepayers. While we contemplated carrying costs would be at issue relative to future balances, we did not authorize

the Company to track and defer past costs for recovery in this case. The Company certainly had notice that pro forma limitation of capacity costs and reevaluation of the recovery mechanism was at issue in the last case. It therefore should have addressed recovery of carrying costs resulting from a delay in recovery of its rate year capacity costs there. Recovery of deferred capacity will be allowed on a prospective basis. We will not go back and reimburse the Company for past costs.

INCENTIVE COMPENSATION

The Hearing Examiner allowed all expenses related to the employee wage and bonus program except expenses for the budget incentive plan. The Examiner rejected the Company's proposal to recover the 1991 test year level of costs associated with the budget incentive plan because the plan is not in effect in the pro forma or rate year. The Company admitted that the plan had expired, and it would not be resurrected for at least three years. Nevertheless, it claims that the Commission should allow the full test year expense associated with the budget incentive plan in order to recognize its strategy of developing special incentive plans from time to time. The plan has expired; it is clearly unreasonable to expect the ratepayers to pay for a program which no longer exists.

The Consumer Counsel and VCCC took exception to the Examiner's recommendation to allow the remainder of the Company's bonus expense. The Consumer Counsel recommended a disallowance associated with the increase in bonuses between 1990 and 1991. The VCCC recommended a limitation on the increase. In the Company's prior case we said that "reasonable incentive payments to encourage

employee performance goals are worthwhile programs which can stimulate production efficiencies." However, we cautioned Virginia Power "to offer sufficient evidence to justify continuing recovery," and we indicated that we would carefully scrutinize any increase over historic levels of the costs of such programs in future cases. The test year incentive plan expenses in this case were $10.6 million higher than the level allowed in the 1991 case. It is that increase that the Consumer Counsel would disallow. The VCCC would simply limit the level of allowed increases to management bonuses.

The Company offered extensive testimony supporting its incentive program and the increase over historic levels. The plan provides an effective way of promoting continuous effort on a corporate and individual level. It appropriately links pay and performance. Virginia Power did present evidence sufficient to justify continuing to recover these employee expenses in its cost of service and to justify the increase over the historic level.

A third program was also at issue in this case. As part of a cost curtailment program, the Company offered a plan of early retirement and estimated about 185 employees would opt to participate, but instead 320 employees retired under the plan. The retirements were effective September 1, 1992. The Consumer Counsel recommended those costs be disallowed. Consistent with our treatment of the Activity Review and Resource Allocation Severance costs in *Application of Virginia Electric and Power Company*, Case No. PUE900023, 1991 S.C.C. Ann. Rept. 279 and Case No. PUE890035, 1990 S.C.C. Ann. Rept. 280, we will allow a full year's effect of the salaries saved offset by the expense

of the program. The payroll adjustment results in a net savings or reduction in the additional revenue requirement.

POST EMPLOYMENT BENEFITS OTHER THAN PENSIONS

We also agree with the Examiner's recommendation to allow recovery of other post-employment benefits ("OPEB") costs on an accrual basis in this case. We adopted rules in Case No. PUE920(X)3 which allow the accrual of employee post-employment benefits other than pensions in the manner prescribed by Statement 106 of the Financial Accounting Standards Board ("FASB") and provide for the recovery in rates of those OPEB costs, including the amortization and recovery of the transition obligation. The Consumer Counsel recommended against such recovery referring to a recent pronouncement of the Emerging Issues Task Force of the Financial Accounting Standards Board that allowed the phase-in of all FASB Statement 106 costs. The Consumer Counsel believed that a phase-in of the costs and deferral would permit all parties an opportunity to evaluate further the costs and examine the underlying actuarial assumptions. Our rules allow the Company to recover OPEB costs if fully funded. The data related to this adjustment were available to all parties and subject to analysis and cross examination. The Company has fully funded the amount of costs in rates, and we see no reason to defer recovery to a later date. If the assumptions prove to be less than 100 percent true or accurate, they can be revised each year as actuaries review the future costs and determine the proper level of accruals.

INTEREST SYNCHRONIZATION

One of the few issues on which we differ from the Hearing Examiner in Phase I is interest synchronization. Consistent with previous decisions, the Examiner recommended continuing use of the capital structure method to compute interest expense for calculating federal income taxes for Virginia Power. Staff and the Company recommended a change to a rate base synchronization method in this case. They asserted that the rate base method provides a more accurate match between interest expense allowed in cost of service and the amount used as a tax deduction. We agree that it is time to change from the capital structure method to the rate base method for making the interest synchronization adjustment for Virginia Power. The capital structure method of calculating interest synchronization for Virginia Power was originally adopted because of nuclear plant abandonments which had been excluded from rate base. The Commission determined that the ratepayer should receive the tax benefit associated with the interest expense on the debt used to finance the abandoned projects. We thus began multiplying dollars of debt in the capital structure by the cost of debt to determine the interest expense for tax purposes. The abandonment costs are now almost fully amortized.

Moreover, since we have now updated rate base, we often, as here, have differing dates between rate base and capitalization. We have in the past approved additional adjustments intended to correct for similar mismatches, but moving back to a rate base approach makes the calculation more straight forward. Further, the information needed to make the further adjustments previously approved was not readily available here as certain financial data was available

only on a quarterly basis. The difference between the interest expense calculated using the rate base and capital structure method is small and accrues to the benefit of the ratepayer in this case. Accordingly, we find the time has come to change Virginia Power's calculation consistent with our treatment for all other Virginia utilities.

INTEREST ON TAX DEFICIENCIES

We will also allow the Company to recover interest paid on prior period tax expenses in its cost of service because the interest component is related to the prior period taxes. The Consumer Counsel recommended against this allowance. We previously determined that prior period tax expenses should be recoverable for ratemaking because the Company's aggressive tax strategy does benefit ratepayers. *Application of Virginia Electric and Power Company*, 1988 S.C.C. Ann. Rept. 274. Interest is certainly an expense related to the prior period tax, therefore it too should be recoverable.

TAX DEPRECIATION CUSHION

The Examiner rejected the Consumer Counsel's proposal to exclude $8 million of tax depreciation cushion in the federal income tax expense. The Examiner concluded that no cushion existed since the original entry was never included in the cost of service. We agree and find that the ratepayer has not been harmed. The Company, however, is instructed to exclude tax cushions in future rate cases and annual informational filings.

LIFE INSURANCE PREMIUM CREDITS

The Examiner adopted the Staff's proposal requiring the Company to refund 1990 and 1991 life insurance premium credits received during the pro forma period. Virginia Power agreed that the amount should be refunded but argued that the refund should be amortized over a three-year period. We adopt the Hearing Examiner's finding that the credits should be immediately refunded. Amortization is not necessary. Moreover, such treatment is consistent with our treatment of the early retirement costs discussed above.

PLANT UPDATE

The Virginia Committee took issue with the rate base update to November 30, 1992, used by all other parties and Staff in this case. Our policy on updating rate base should be clear. In *Application of Virginia Natural Gas. Inc.*, 1991 S.C.C. Ann. Rept. 292, 294, we clearly stated that:

> We find the update adjustment to be appropriate in this rate case, irrespective of whether a showing of attrition has been made. Experience with the adjustment from previous cases indicates it yields the most current and therefore most accurate snapshot of rate base given current economic conditions. If an attrition problem exists the updated figures help alleviate it. But even if attrition is not shown, the adjustment is still a reliable method of determining rates based on the most current data.

The methodology used by Staff in this case to update the rate base has been previously adopted by the Commission in numerous proceedings, and it will be accepted here.

CASH WORKING CAPITAL

Only two components of the calculation of Company's cash working capital requirement were in controversy in this case. First, Staff and the Virginia Committee calculated the revenue lag using a daily average for gross accounts receivable rather than the monthly average used by the Company. The Company offered new information providing jurisdictional lag days in rebuttal testimony, but the Examiner found that use of a daily average for gross accounts receivable is reasonable. We will accept his recommendation here. We agree that the Company's jurisdictional study should be audited and reviewed prior to implementation.

The second controverted component of cash working capital was Staff's recommended dividend expense lead adjustment. Staff asserted that common equity dividend payments are necessary as ongoing costs of doing business and hence must be considered part of the working capital. The Examiner properly rejected Staff's proposal. The purpose of the cash working capital allowance is to allow the Company to recover carrying costs associated with funding its daily operations. The payment or timing of a dividend should not affect the cash working capital allowance.

CAPITAL STRUCTURE

The Examiner adopted the Staff's proposal to use an actual December 31, 1992 capital structure, with the cost of Company's variable rate securities and its common equity updated through February, 1993. We agree with the Examiner that the Staff's proposed capital structure and cost of senior capital should be adopted. Although the Consumer Counsel agreed with the Hearing Examiner's recommendation to use a December 31, 1992 capital structure, he argued that the capital structure should include one-half of the rate year refunds ordered in the last case. The Hearing Examiner properly rejected that proposal. As he noted, the temporary use of money does not convert funds into "invested capital." When the Company is authorized to place interim rates in effect, any and all money flowing from those rates is subject to being refunded with interest to the customer. The money is not the Company's money unless and until the Commission authorizes the Company to keep all, part, or none of the funds.

RETURN ON EQUITY

The Company is currently authorized a rate of return on equity in the range of 11.5% to 12.5%. The recommendations of the cost of equity witnesses in this case ranged from 10% to 12.75%. Certainly a reduction in the Company's current 11.5% to 12.5% allowed return on equity is indicated by almost any measure of the cost of equity capital discussed by the financial witnesses. We agree with the Hearing Examiner's recommended range of 10.5% to 11.5% for the Company's cost of equity.

Both Company and Staff witnesses included a flotation adjustment in their cost of equity. In the last case, we declined to adopt an accounting adjustment for recovery of the jurisdictional portion of test year issuance expenses. We approved a range for the cost of equity incorporating our consideration of continuing flotation costs that Dominion Resources, Inc. bears in issuing equity. The Hearing Examiner here incorporated consideration of continuing flotation costs in his recommended range of 10.5% to 11.5%. We find that consideration to be appropriate.

GENERATING UNIT PERFORMANCE

In 1981 the Commission established a generating unit performance improvement program designed to recognize the impact of generating unit performance on fuel expenses. Once the range for the return on equity has been established, the return selected for calculating revenue requirement is a function of generating unit performance. Equity returns at the bottom of the range reflect less than average performance levels while equity returns at or near the top recognize sustained outstanding generating performance. In 1989, the Company's nuclear units suffered an extended outage. Accordingly, the return on equity was lowered to the mid-point of the equity range to calculate the Company's revenue requirement. The Company also was disallowed recovery of a significant portion of the additional costs incurred as a result of the outage. The Company's performance rebounded, and in the 1991 case, the revenue requirement was calculated at a return 25-basis points above the mid-point of the range. The Company's test period performance in this case was described by Staff as exceptional. Staff recommended the equity return be

established at or near the top of the approved range. The Hearing Examiner determined that the Company should show a further sustained effort before qualifying for an increase to the top of the range. Therefore, he maintained that the revenue requirement should continue to be set at the three-quarter point of the equity range. As the Hearing Examiner noted, traditionally, the Commission has acted in 25-basis point increments. However, such increments are not mandatory. We agree with Staff's recommendation to establish the equity return near the top of the approved range. The Company's generating performance has been stellar. Accordingly, we will set the equity return at 90% of the approved range, or 11.4%.

PURCHASED POWER INCENTIVE PROGRAM

Staff witness Stephens recommended the Commission consider expanding its generating unit performance program to include the utility's efforts towards capacity acquisition via its purchased power program. Staff noted that purchased power contracts account for as much as 23% of the Company's total capacity resource base and that in the Company's last fuel factor filing net power purchases accounted for approximately 25 % of projected in-period energy requirements and 39.8% of projected fuel expenses. The Hearing Examiner rejected Staff's proposal. However, we believe such a proposal warrants further consideration. The Company, Staff and any interested parties are directed to explore this concept and present testimony in Virginia Power's next rate case on whether such a program should be implemented and what standards should be incorporated if such a program is adopted. We will address this proposal further in the next case whether it is an expedited or general

case. Moreover, if we decide to implement such a program, it may be applied in setting the return in that same case.

REVENUE REQUIREMENT

Based on our resolution of the issues discussed above and further discussed in the Examiner's reports, Virginia Power's additional revenue requirement is $241,896,000, calculated as follows:

	(000)
Adjusted Operating Income, per Hearing Examiner	$485,080
To reflect the FIT effect of computing interest synch on a rate base method using Staff's rate base, SDL-54, Col. (7)	(33)
To reflect the FIT-interest synch effect (rate base method) of changes to Staff's rate base adopted by the Commission	200
Adjusted Operating Income, per Commission	$485,247
Rate Base, per Hearing Examiner	$6,972,009

To reflect changes in cash working capital due to changes in FIT and ROE	(94)
Rate Base per Commission	$6,971,915
Overall cost of capital at 11.4% ROE	9.191%
Required Adjusted Operating Income	640,789
Adjusted Operating Income per Commission	485,247
Net Requirement	155,542
Revenue Conversion Factor	.640839
Revenue Requirement including Late Payment Revenues	242,716
Less: Late Payment Revenues	820
Revenue Requirement	$241,896

COST ALLOCATION AND REVENUE ALLOCATION

The Hearing Examiner supported the Company's retail class cost of service study continuing the established use of the average and excess method of allocating costs. He noted that it has been the basis of cost of service studies approved

in every Virginia Power rate case since the early 1970s. In this case, however, Virginia Power performed four different production demand allocations. The first demand allocator was the average and excess method historically used for Virginia Power, but the Company also provided allocation studies based on a summer/winter peak and average, summer/winter peak, and the average of 12 coincident peaks. We agree that the average and excess method of allocating costs should be used in the cost of service study on which we rely to determine the proper allocation of revenues in this case. However, as we have recently noted, there is no scientifically correct method for allocating costs. Cost of service studies are useful tools which can be used as guides in apportioning a company's revenue requirement.

We have stated that:

> [C]lass cost of service studies do not determine the actual cost of serving any particular class of customers. They are instead mere estimates of class cost of service. Sound ratemaking appropriately recognizes the importance and place of estimates in apportioning revenue.

Application of Virginia Natural Gas, Inc., 1991 S.C.C. Ann. Rept. 297, 298. *Also see Application of Commonwealth Gas Services, Inc.*, Case No. PUE920037, Final Order dated October 15, 1993 and *Application of Virginia Natural Gas. Inc.*, Case No. PUE920031, Final Order dated June 22, 1993. Since some judgment is required in any cost of service study, we will expect the Company to provide more analysis in the next case as outlined below.

It is clear that the residential class is generating a class return below the Company's overall return in all of the studies developed on this record. We therefore agree with the Virginia Committee and the AOBA that some further movement towards parity of class returns is warranted, but we must guard against rate shock to the residential class. We find that, in this case, all classes should be moved towards parity by approximately the same amount based on the average and excess allocation method. We will approve the allocation to the classes as set forth in Attachment A to this Order. Each class, with the exception of churches, is moved approximately 43% closer to parity. The allocation to churches results in a smaller movement for that class but will result in a percentage increase in rates comparable to the residential class.

In the next case the Company should file the results of five different cost of service studies, specifically using the average and excess method now used for Virginia, the 12 coincident peak method currently used at the Federal Energy Regulatory Commission, the summer/winter peaking average method now used in North Carolina, the summer/winter peak method, and the peak responsibility or one coincident peak method. Those studies should also include the new GS rate schedules. So our intention is clear, however, at this time we do not intend to average those five studies; they provide several different perspectives which should be examined.

RESIDENTIAL CUSTOMER CHARGE

The Company proposed to increase the Residential Schedule 1 customer charge from $6.25 to $7.00. The VCCC argued that the charge was not justified. It contended

that distribution plant should be classified on a demand not a customer basis. We agree with the Examiner that a minimum distribution system is essential to deliver electricity. VCCC's methodology would not properly reflect a minimum distribution system. The Company's embedded cost analysis would support a charge even higher than $7, hence we find the Company's proposed residential customer charge reasonable.

SECONDARY DISTRIBUTION FACILITIES COST

The Virginia Committee and Philip Morris asserted that secondary distribution costs had been inappropriately allocated to Schedule GS-4 which uses no secondary distribution facilities because those customers take service at primary or transmission voltage levels. The remedy proposed by the Virginia Committee and Philip Morris was to assign $5.5 million of secondary distribution demand costs to Schedules GS-3 or GS-2. We find reasonable the position that those secondary distribution costs should not be assigned to GS-4. However, it is not clear precisely how the costs should be reassigned. In addition, without careful study, it is not clear whether other costs have been assigned to other GS schedules which should have been more properly assigned to the GS-4 class. The allocation among the GS rate classes was done by combining the old Schedules 5 and 6 costs and then allocating those costs to the new Schedules GS-1 through GS-4. The Company testified that it did not have a full year of valid load data on the new rate classes. We simply do not have all the data required to make an accurate allocation among the GS classes in this case. Accordingly, we will not make the adjustment proposed by the Virginia Committee and Philip Morris. The Company should carefully scrutinize all costs

assigned to the GS classes when it conducts the requisite cost of service studies in its next case. It should have adequate load data for GS-1 through 4 to support any necessary shifts at that time.

We also note that our decision not to reallocate the secondary distribution costs is conceptually distinct from our acceptance of the Hearing Examiner's recommendation to provide a transmission discount of 2.4% from the separately stated power supply demand charge within Schedule 65-4. In the latter case, costs are moved within the class rather than among classes.

SURPLUS ENERGY RATE

The Virginia Committee recommended the Commission adopt a new surplus energy rate. The Company agreed to study the proposal, meet with Staff and interested parties, and file an experimental tariff within 6 months of the final order in this case. We encourage the Company to work with its customers and our Staff. We will review any such proposed rate and the supporting justification when it is filed.

GS IMPLEMENTATION GUIDELINES

In comments to the Hearing Examiner Report, Virginia Power asked the Commission to approve the procedures set forth in Company witness Evans' rebuttal testimony to allow certain customers receiving service under Schedules 5 or 6 prior to October 27, 1992 to migrate back to those schedules at the conclusion of this case. We agree that such migration should be allowed. Customers who made a decision to migrate from Schedules 5 or 6 to Schedules GS-1 through

4 based upon interim rates should have the option of going back to Schedule 5 or 6 if final rates approved herein show those schedules to be more advantageous. We emphasize, however, that migration back to Schedules 5 and 6 will not be a permanent feature of the Company's rates and we will move forward to phase out Rate Schedules 5 and 6.

Virginia Power originally proposed that the rates for Schedules 5 and 6 be increased by 128.8% and 137.6% respectively, of the overall percentage increase. The Staff recommended that the increase be 137.5 % of the overall increase for both schedules. The Company agreed to this increase on rebuttal. However, the Company and Staff disagreed with respect to future increases. The Company proposed that future Rate Schedules 5 and 6 increases be based on 150% of the overall increase. Staff recommended, and we believe, that it is more appropriate to reserve judgment regarding future increases. Any future increases to Rate Schedules 5 and 6 should be based on the specifics of the case while phasing out Rate Schedules 5 and 6 in a reasonable manner.

SCHEDULE 10

The Commission allowed Virginia Power to implement Rate Schedule 10 on an experimental basis in 1989. The Company completed its final evaluation and presented its findings and proposed modifications in this case. Staff witnesses reviewed the proposed Schedule 10 and recommended that it be made permanent and available to up to 200 customers. The Company accepted that recommendation. Staff further recommended that the Company should update its proposed "A" day rate to include current estimates of combustion turbine capacity costs. The

Company resisted the update because this record does not support a proper update of all of the costs associated with the rate. The Examiner concurred. He found that all parts of the costs should be reviewed before changing the rate, and we agree. We will accept the changes to Schedule 10 exclusive of the partial update as recommended by the Examiner, but we will not make Rate Schedule 10 permanent until such time as the Company is prepared to offer the rate to any and all interested customers. Schedule 10 will continue on an experimental basis limited to 200 customers with Staff's changes, except the "A" day update.

PHASE II

SUMMER/WINTER DIFFERENTIAL AND LINE EXTENSION POLICY

Virginia Power also proposed a new line extension policy which would require all new residential service connections to pay a service fee of approximately $1,300. The fee would be treated as a contribution in aid of construction. Under the Company's proposal, each newly connected residence would be eligible for a credit to off-set the service fee. The size of the credit would depend on the amount of electricity used. A new resident with an all electric house would usually have the fee entirely offset by the credit.

The Company also proposed to increase the tail block charged for the summer billing months of June through September from 6.899¢ per kwh to 8.317¢ per kwh. The Company proposed increasing the tail block for the remaining winter billing months from 4.215¢ per kwh to 4.608¢ per kwh. The differential between the summer and winter months would thus be increased from 2.684¢ per

kwh to 3.709¢. The Company claimed that both rate design proposals were offered in an attempt to assess costs more properly. A number of the Protestants in Phase II of this proceeding, however, objected to the Company's proposals.

The Company's proposals must be rejected. Virginia Power's proposed changes were not supported by the evidence; there was inadequate analysis offered by the Company, and there were too many unanswered questions. Rather than relying on data and analysis, the Company urged approval of what must be described as a drastic change in its residential line extension policy and an almost 40% increase in the summer/winter differential of the tail block of the residential rate because the changes were "cost-based." As the Company well knows, there can be many rate designs to recover the same revenue, each of which could be fairly termed "cost-based." This label, without more, does not suffice. Proposed rate changes must be analyzed and supported and their effects studied. In addition, alternatives must be reviewed. In short, proposals such as those made by the Company here must be shown to be consistent with or a part of a comprehensive integrated resource plan. Rate design, planning, and conservation and load management must be coordinated.

While Virginia Power's analysis of both proposals was lacking, there was a more disturbing lack of data supporting the Company's proposed line extension policy. First, the Company failed to show that the deteriorating residential class rate of return was tied to or caused by the increase in new residential connections. Also, the Company did not perform a life cycle analysis of new distribution plant to determine whether there is a significant subsidy problem. Further, the Company made no study of how the proposed

line extension policy would affect capacity and energy requirements or conservation or load management. This failure conflicts with the clear directive in our 1992 Conservation and Load Management ("CLM") Order in which we specifically stated that cost effective CLM should be pursued and that rate design could be a powerful tool which can be used to achieve optimal CLM objectives. The Company does not know whether the line extension policy would increase or decrease total costs over the long term. The Company did not consider the impact of its proposals on the need for generating capacity in the future. The Company did not even study what impact the proposed plan would have on the number of all electric homes; instead, Virginia Power assumed that the new policy would have no impact on the electric use of new customers. These and many other legitimate issues and questions were dismissed by the Company as being "extraneous."[1]

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[1]Specifically, in his prefiled rebuttal testimony, Company witness Hilton stated that it had been suggested that the Company's proposals would

> (1) decrease competition, (2) adversely effect conservation and load management programs, (3) restrict consumer choices, (4) require additional transmission lines, (5) harm the environment, (6) result in less efficient use of natural resources, and (7) impede economic growth.

Exhibit EPH 48, pp. 8-9

Mr. Hilton responded as follows:

> The Commission should not let these externalities cloud the main focus in this case. The questions before the Commission are whether our proposals are reasonable and

(continued...)

These matters are not "extraneous," and they must not be dismissed. These and other similar issues are integral parts of proper planning that considers the results of the Company's actions. In the future, when the Company presents significant new rate designs, it should show how such designs impact its integrated resource planning and why the proposals were chosen over other alternatives.

The Commission has recognized the Company's excellence in the power production area; we urge the Company to move to the same level of excellence in the coordination of its planning, rate design, and conservation and load management.

PHASE III

CAPACITY COSTS DISALLOWANCE ASSOCIATED WITH THE GROSS RECEIPTS TAX ERROR

One final issue was addressed in Phase III of this case. Specifically, Staff witness Thomas E. Lamm recommended that the Commission disallow the portion of Virginia Power's capacity expense associated with contracted power

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[1](...continued)
cost-based. The Company should not be impeded, by extraneous concerns, from offering proposals to control its costs and keep rates down. Likewise, the Commission should not constrain itself from taking action to correct the subsidy problems identified by the Company and should avoid debates on environmental and economic issues which may have no clear answers.

Exhibit EPH 48, p. 9.

purchases from certain non-utility generators ("NUGs"). Staff had discovered that the Company had included gross receipts tax ("GRT") in the calculation of Virginia Power's avoided cost which was the basis for capacity payments to a number of NUGs. In his Report, the Examiner found that there was no dispute that a GRT element was included in the calculation of numerous payments. GRT, however, is not avoided when a utility purchases power. It is a function of revenue and must be paid regardless of whether Virginia Power builds new capacity or purchases capacity from a NUG. In fact, no one on this record has argued that it is proper to include gross receipts tax in the calculation of the costs avoided by Virginia Power when it purchases from NUGs. Rather, the Company and several Protestants admit that GRT should not be included in the calculation of the Company's avoided costs. Thus, Staff clearly showed that an error had been made which caused capacity payments to be higher than they would have been absent the error.

Although the Company and many of the Protestants agreed that GRT should not be included in the calculation of avoided costs, they asserted that removing GRT from the calculation was not correction of an error, but rather refinement of the methodology. We disagree. Including GRT in the calculation was a clear and undisputed error and that is much different than "a refinement of the methodology" used to calculate avoided costs. The question of whether to include gross receipts tax is not methodological. An item has been included in avoided costs which clearly could not have been an avoided cost. The error should be corrected. We find that ratepayers should not have to bear a portion of capacity costs that are not truly avoided and hence are in excess of the Company's avoided costs. The recovery level of non-utility capacity costs should be reduced for the

effects of the improperly included gross receipts tax component.

The Company and Protestant witnesses identified several modeling assumptions and methodological changes that are reasonably described as enhancements or refinements and reflect progression along the learning curve. We draw a sharp and distinguishing line between learning curve enhancements or refinements and pure error. We recognize that the Federal Energy Regulatory Commission regulations allow rates for purchases to be based upon estimates of avoided costs and that reliance on estimates does not violate the avoided cost standard. Moreover, this Commission has long allowed accommodations in the refinement of the avoided cost methodology. However, GRT inclusion is not a refinement of the avoided cost calculation. As noted by one witness, the proper standard of review must be the reasonableness of the estimates in the context of the information known at the time. The Company is well aware of the functioning of gross receipts tax and reasonably should have known that such tax was not avoided when power was purchased from a NUG.

The Virginia Supreme Court has held that we have reasonable discretion to disallow any part of expenses actually incurred where the evidence shows such expenses are exorbitant, unnecessary, wasteful or extravagant. *Lake of Woods Utility Co. v. Corp. Comm.*, 223 Va. 100 (1982). Here purchased power costs are unnecessary and excessive because an undisputed error was made. It is not fair to the ratepayers to expect them to continue paying for the Company's GRT twice, once as a tax expense and again, erroneously, as a component of the Company's capacity expense. The Commission has a statutory duty to establish

just and reasonable rates and to substitute just and reasonable rates if, upon investigation, a rate is found to be based on excessive costs. That is what we must do here.

It is also important to note that the disallowance ordered here is not retroactive. Staff has not recommended a retroactive disallowance of all or any portion of capacity payments already made but only a reduction in capacity costs included in the Company's cost of service effective with the interim rates in this case. Once the Company's avoided costs upon which its capacity costs were based were challenged by a showing that an error had been made, it became the Company's burden to show that its capacity costs were reasonable. That burden was not met.

We are also aware that our action here may have an effect on purchased power contracts through a contract clause referred to as the regulatory out clause; however, the operation of those clauses is not before us here. Staff has recommended disallowance of costs resulting from the GRT error from Virginia Power's rates but has not recommended reformation of non-utility contracts. Operation of specific mutually negotiated contract clauses should be left to the contract remedies available to Virginia Power and its power suppliers.

The Company classified a number of potentially affected NUG contracts into several categories in its rebuttal testimony: (l) NUGs with rates based on an early non-differential revenue requirement avoided cost that was approved by the Commission and set forth in the Company's Schedule 19 with limited applicability; (2) NUGs with "Schedule 19-type" capacity rates that were not explicitly covered by that standard offer; (3) NUGs with

rates approved by the Federal Energy Regulatory Commission ("FERC"); (4) NUGs with rates based on Virginia Power's Chesterfield Unit 7 avoided costs; (5) NUGs whose rates were specifically ordered by the Commission in arbitration proceedings; and (6) NUGs with contracts entered into pursuant to later Schedule 19 rates approved by the Commission. Staff recommended disallowance of the GRT portion of the capacity costs related only to categories 2 and 4. We believe that is appropriate. In both cases, the Company established rates based on avoided costs including the GRT. We, however, will not reduce an expense which the FERC or we have reviewed, approved and explicitly ordered as was done in the remaining categories.

Our calculation of the disallowance does include payments under the Appomattox Cogeneration contract, however. Appomattox Cogeneration does not have a contract rate approved by the Commission in an arbitration proceeding. Although such result was alleged by Appomattox Cogeneration, the arbitration proceeding between Continental Forest Industries, Inc. (Appomattox Cogeneration's predecessor) and Virginia Power related to the timing of the applicability of pricing provisions already agreed to by Virginia Power and Continental Forest. The arbitration proceeding did not constitute a review and approval of the rate. *Arbitration Proceeding Between Continental Forest Industries, Inc. and Virginia Electric and Power Company*, Case No. PUE820052, 1983 S.C.C. Ann. Rept. 367.

Hopewell Cogeneration also offered testimony that it had a blended and, therefore, negotiated rate with no gross receipts tax component ascertainable. The evidence offered

herein, however, reveals that the rate has a tier which includes gross receipts tax and a second tier which appears to be negotiated rather than based on an avoided cost calculation. We find capacity expenses related to the first tier payments are subject to disallowance because the rate was based on an avoided cost which included the GRT.

Since the Commission has retained deferred accounting treatment for purchased capacity expenses in this case, this same deferral mechanism provides a logical means to account for the disallowance of capacity expense without changing the revenue requirement found reasonable above. We will require Virginia Power to credit deferred capacity expenses monthly by an appropriate amount to eliminate the disallowed GRT component of actual capacity expense. Such accounting should be effective October 27, 1992, and continue until the Company's next rate proceeding when an appropriate level of purchased capacity expense can be included in the revenue requirement. In that rate case we can review the actual level of the credit.

NOW, THEREFORE, IT IS ORDERED:

(1) That the findings and recommendations of the Hearing Examiner's September 3, 1993 and October 22, 1993 Reports, as modified herein, are adopted;

(2) That Virginia Power shall forthwith file revised tariffs designed to produce $241,896,000 in additional gross revenues effective for service rendered from October 27, 1992;

(3) That the Company, Staff and any interested parties shall explore expanding the generating unit performance

program to include evaluation of the utility's purchased power capacity acquisition program and present testimony thereon in Virginia Power's next rate case;

(4) That Virginia Power shall file the results of five different cost of service studies more fully described above in its next rate case;

(5) That Rate Schedule 10 shall continue on an experimental basis until further order of the Commission;

(6) That Virginia Power shall credit deferred capacity expenses monthly by an appropriate amount to eliminate the disallowed GRT component of actual capacity expense;

(7) That, on or before May 2, 1994, Virginia Power shall refund with interest as directed below, all revenues collected from the application of the interim rates which were effective for service beginning October 27, 1992, to the extent that such revenues exceeded the revenues which would have been produced by the rates approved herein;

(8) That interest upon such refunds shall be computed from the date payment of each monthly bill was due during the interim period until the date refunds are made, at an average prime rate for each calendar quarter. The applicable average prime rate for each calendar quarter shall be the arithmetic mean, to the nearest one hundredth of one percent, of the prime rate values published in the Federal Reserve Bulletin or in the Federal Reserve's Selected Interest Rates ("Selected Rates") (Statistical Release G. 13), for the three months of the preceding calendar quarter;

(9) That the interest required to be paid shall be compounded quarterly;

(10) That the refunds ordered in paragraph (7) above, may be accomplished by credit to the appropriate customer's account for current customers (each such refund category being shown separately on each customer's bill). Refunds to former customers shall be made by a check to the last known address of such customers when the refund amount is $1 or more. Virginia Power may offset the credit or refund to the extent no dispute exists regarding the outstanding balances of its past or current customers. To the extent that outstanding balances of such customers are disputed, no offset shall be permitted for the disputed portion. Virginia Power may retain refunds owed to former customers when such refund amount is less than $1; however, Virginia Power will prepare and maintain a list detailing each of the former accounts for which refunds are less than $1 and in the event such former customers contact Virginia Power and request refunds, such refunds shall be made promptly. All unclaimed refunds shall be handled in accordance with Va. Code § 55-210.6:2;

(11) That on or before June 2, 1994, Virginia Power shall file with the Staff a document showing that all refunds have been lawfully made pursuant to this Order and itemizing the cost of the refund and account charged. Such itemization of costs shall include, *inter alia.* computer costs, personnel hours, associated salaries and costs for verifying and correcting the refund methodology and developing a computer program;

(12) That Virginia Power shall bear all costs of the refunds directed in this Order; and

(13) That, there being nothing further to come before the Commission, this matter shall be removed from the docket and the papers placed in the file for ended causes.

AN ATTESTED COPY hereof shall be sent by the Clerk of the Commission to Kendrick R. Riggs, Esquire, Virginia Electric and Power Company, 1200 One River Front Plaza, Louisville, Kentucky 40202; Pamela Johnson, Esquire, Virginia Electric and Power Company, P.O. Box 26666, Richmond, Virginia 23261; Evans B. Brasfield, Esquire, Hunton & Williams, Riverfront Plaza, East Tower, 951 East Byrd Street, Richmond, Virginia 23219-4074; Edward L Petrini, Esquire, Office of the Attorney General, Division of Consumer Counsel, 101 North 8th Street, 6th Floor, Richmond, Virginia 23219; Frann G. Francis, Esquire, 1050 17th Street, N.W., Suite 300, Washington, D.C. 20036; Louis R. Monacell, Esquire, 1200 Mutual Building, Richmond, Virginia 23219-3095; Jean Ann Fox, President, Virginia Citizens Consumer Council, 114 Coachman Drive, Yorktown, Virginia 23693; Edward L. Flippen, Esquire, and Charles H. Tenser, Esquire, Mays & Valentine, P.O. Box 1122, Richmond, Virginia 23208-1122; David B. Kearney, Esquire, City of Richmond,900 East Broad Street, Suite 300, Richmond, Virginia 23219; Stephen H. Watts, II, Esquire, and Mark J. LaFratta, Esquire, McGuire, Woods, Battle & Boothe, One James Center,Richmond, Virginia 23219-4030; T. Randolph Perkins, Esquire, 9405 Arrow Point Boulevard,Charlotte, North Carolina 28217; Oliver A. Pollard, III, Esquire, Southern Environmental Law Center, 201 West Main Street, Suite 14, Charlottesville, Virginia 22901; Frederick H. Ritts, Esquire, 1025 Thomas Jefferson Street, N.W., Washington,D.C. 20007; Stanley W. Balis, Esquire, 1101 14th Street, N.W., Suite 1400, Washington, D.C.20005; Dennis R. Bates, Esquire, Fairfax County Board

of Supervisors, 12000 Government Center Parkway,Fairfax, Virginia 22035-0064; Denise Waters Bland, Esquire, College of William and Mary, Williamsburg, Virginia 23187; Donald R. Hayes, Esquire, 1100 H Street, N.W., Washington, D.C. 20080; Eric M. Page, Esquire, 316 West Broad Street, Richmond, Virginia 23220-4257; Donald A. Fickenscher, Virginia Natural Gas, Inc., 5100 East Virginia Beach Boulevard, Norfolk, Virginia 23502-3488; Timothy R. Dunne, Esquire, P.O. Box 22477, Houston, Texas 77227-2427; Mr. J.B. Hall, Jr., Suite 700, Plantation House, 1108 East Main Street, Richmond, Virginia 23219; Laurence M. Hamric, Esquire, Williams, Mullen, Christian & Dobbins, 1021 East Cary Street, Richmond, Virginia 23210-1320; Marjorie R. Philips, Esquire, 300 South Grand Avenue, Los Angeles, California 90071; Philip F. Abraham, P.O. Box 788, Richmond, Virginia 23206; and to the Divisions of Public Utility Accounting,Economics and Finance and Energy Regulation.

A True Copy
Teste:
/s/ William J. Bridge

Clerk of the
State Corporation Commission

ATTACHMENT A

VIRGINIA ELECTRIC AND POWER COMPANY
CASE NO. PUE920041

SUMMARY FOR ROR, INDICES & % INCREASES

	VIRGINIA JURISDICTION	RESIDENTIAL	GS-1	GS-2	GS-3	GS-4	TOTAL CHURCHES	OUTDOOR LIGHTING	TOTAL
RATE BASE	$6,972,009	$4,197,412	$388,867	$1,008,753	$910,891	$423,739	$25,541	$17,807	$6,972,009
PRESENT ROI	$485,088	$237,181	$44,782	$103,983	$39,499	$37,098	$1,338	$1,388	$485,088
ROR BEFORE INCREASE	6.96%	5.65%	11.52%	10.38%	6.53%	8.78%	4.85%	7.79%	6.96%
INDEX BEFORE INCREASE	100.0	81.2	165.5	149.0	93.9	126.1	69.7	111.4	100.0
REVENUE INCREASE	$241,896	$166,787	$6,715	$22,108	$33,086	$11,729	$986	$564	$241,895
ROI AFTER INCREASE	$640,096	$344,014	$49,985	$118,078	$80,703	$44,614	$1,870	$1,741	$640,096
ROR AFTER INCREASE	9.18%	8.20%	13.62%	11.70%	8.86%	10.55%	7.32%	9.78%	9.18%
INDEX AFTER INCREASE	100.0	89.3	137.5	127.5	96.5	115.0	79.8	106.5	100.0
ROR MOVEMENT		42.88%	42.78%	42.78%	42.78%	42.78%	33.35%	42.78%	
REVENUE INCREASE	$241,896	$166,787	$6,715	$22,108	$33,086	$11,729	$986	$564	$241,895
BASE REVENUE	$2,363,814	$1,348,130	$155,104	$390,968	$297,310	$138,018	$7,385	$5,909	$2,363,814
FUEL REVENUES @ 1.419c	$653,858	$282,606	$32,478	$119,933	$126,450	$91,278	$1,838	$1,869	$653,858
TOTAL REVENUES	$2,916,672	$1,536,730	$187,576	$510,681	$421,760	$249,296	$8,933	$6,918	$2,915,672
% INCREASE TOTAL	8.29%	10.89%	3.58%	4.33%	7.84%	4.70%	11.05%	8.15%	8.30%
TIMES THE AVG. INCR.		1.31	0.43	0.52	0.95	0.57	1.33	0.98	1.00
% INCREASE BASE	10.69%	13.36%	4.33%	5.69%	11.13%	7.42%	13.36%	9.54%	10.69%
TIMES THE AVG. INCR.		1.25	0.41	0.53	1.04	0.69	1.25	0.89	1.00

COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

AT RICHMOND, MARCH 7, 1994

APPLICATION OF

VIRGINIA ELECTRIC AND POWER COMPANY

CASE NO. PUE920041

For a general increase in rates

ORDER ON RECONSIDERATION

On February 17, 1994, Hopewell Cogeneration Limited Partnership ("Hopewell Cogeneration") filed a Petition for Reconsideration of a portion of the February 3, 1994 Final Order issued in this proceeding ("Final Order"). Hopewell Cogeneration specifically petitioned for reconsideration of our finding that the capacity payments made by Virginia Electric and Power Company ("Virginia Power") to Hopewell Cogeneration contain a "tier which includes gross receipts tax" for which Virginia Power was denied rate recovery. Hopewell Cogeneration alleges that the finding "appears to be based on a misunderstanding of the uncontroverted facts and should be reversed."

In support of its petition, Hopewell Cogeneration refers to the testimony of William P. Utt, Executive Vice President of CRSS Capital, Inc., the developer and one of the owners of Hopewell Cogeneration. Mr. Utt asserted that capacity payments to Hopewell Cogeneration are negotiated rates resulting from blending two separate pricing proposals to

arrive at a weighted average price that has no identifiable gross receipts tax ("GRT") component. He further testified that the blended rate was derived by weighting the initial rate, based on Chesterfield 7 combined cycle unit estimated costs including GRT, at 84.15%. Hopewell Cogeneration recites the applicable contract provision in its Petition which clearly provides that Virginia Power will purchase 84.15% of dependable capacity at the rate of $11.1975/kW per month for the first fifteen years and $6.4333/kW per month for the remaining ten contract years. The contract further provides that the remaining 15.85% of capacity will be purchased at the rate of $4.9229/kW per month stated in 1988 dollars and escalated under the contract. Hopewell Cogeneration asserts that every kW is priced at the 84.15%/15.85% weighted average or blended rate. These percentages, it alleges, do not create tiers of capacity -- "*They only represent components for calculating the negotiated weighted average price applicable to all capacity.*" (Emphasis in the original.)

Chesapeake Paper Products Company ("Chesapeake") filed a Petition for Reconsideration on February 23, 1994. Chesapeake sought reconsideration of that portion of our Final Order which disallowed capacity expenses to the extent that they were attributable to the erroneous inclusion of GRT in the calculation of certain capacity payments. Specifically, Chesapeake asserts that the evidence related to its contract with Virginia Power does not support the conclusion that a GRT component was included in the calculation of Chesapeake's rate. In its petition, Chesapeake states that "[e]ven though the payment structure was intended to generally follow the structure of avoided cost payments approved in Schedule 19 proceedings, the evidence is unequivocal that the actual capacity rate

Chesapeake receives was based on a negotiated rate." Chesapeake further asserts that Virginia Power witness Carney "assumes that a gross receipts tax rate was used in developing generation costs for the original avoided cost payments in Case No. PUE80012, but he cannot be certain." (Emphasis in the original.) Thus, Chesapeake argues, there is no mechanism for separately identifying a GRT component in its rate.

Union Camp Corporation also filed a Petition for Reconsideration on February 24, 1994. Union Camp urges us to adopt the Hearing Examiner's recommendation to allow all capacity costs to be recovered in rates regardless of the error in the calculation of capacity payments. Union Camp asserts that the Final Order arbitrarily discriminates against contracts not approved by the Commission. Moreover, Union Camp argues that "[i]t is fair for Virginia Power's ratepayers to shoulder the cost of the error for the duration of existing contracts."

We issued an Order Granting Reconsideration on February 24, 1994, for the sole purpose of considering further our decision on the gross receipts tax issues raised in the Petitions filed by Hopewell Cogeneration, Chesapeake and Union Camp. The limited purpose of our reconsideration was reiterated by our Order dated February 25, 1994, directing Virginia Power to implement the rates and refunds declared lawful by the February 3, 1994, Final Order since the gross receipts tax issues raised in the Petitions did not affect Virginia Power's revenue requirement in this case.

It is important at the outset of our discussion on consideration of the petitions before us to articulate clearly the question which must be addressed and we believe Union

Camp has properly framed the question in its petition. We must determine whether the ratepayer should bear a portion of Virginia Power's capacity costs that are not truly avoided and result from the utility's error. Union Camp asserts that the ratepayers should bear such an expense for the duration of the contracts because $2 million a year is a "minuscule" cost. Union Camp would also characterize this error as a conceptual one rather than a simple arithmetic error like 1+1=3. We reach another conclusion than does Union Camp based on the record before us. We are of the opinion and continue to find that the ratepayer should not bear any responsibility for an error Virginia Power made in the calculation of capacity payments, an error which we find to be more basic than 1+1. No addition was necessary at all. Gross receipts taxes should not have been included in the calculation. Moreover, the limitations placed on the disallowance are not arbitrarily discriminatory. Although GRT was also included in the calculation of payments under contracts specifically approved by the Commission or the Federal Energy Regulatory Commission, we did not include those costs in the calculation of the disallowance. We are of the opinion that it would not be reasonable to reduce an expense which we have reviewed, approved and explicitly ordered Virginia Power to pay. That, however, is not the case with those costs included in the disallowance. The relief requested in Union Camp's petition should be denied.

As we stated in the Final Order, we realize that our decision here will affect some of the purchase power contracts as a result of mutually negotiated regulatory out clauses, but we must emphasize that we are investigating the level of Virginia Power's rates to its retail customers in this case. We are not attempting to reform capacity payments in individual contracts. Accordingly, we must evaluate

Virginia Power's costs of service and determine whether they are just and reasonable. The Staff identified an error which Virginia Power admitted was made in the calculation of numerous rates. GRT is not a cost avoided when power is purchased from a non-utility developer. Thus, we are compelled to disallow the unnecessary and excessive capacity costs attributable to that error.

We appreciate that it is difficult to remain focused on the essential question in the third phase of this rate case - the reasonable level of the cost of service built into Virginia Power's rates. It, however, is well established that we have reasonable discretion to disallow any part of expenses where the evidence shows such expenses to be unnecessary or excessive. When the evidence before us established that an error had been made which caused Virginia Power's capacity costs to be higher than they would have been absent the error, we had reasonable grounds to conclude that Virginia Power's costs were unnecessary and excessive and then to substitute just and reasonable rates for those found to be based on excessive costs. Based on the facts before us we concluded that Virginia Power's ratepayers should not bear the burden of that error.

The relief requested in Hopewell Cogeneration's petition also must be denied. Based on the petition itself and Mr. Utt's testimony, it is clear that the capacity payment Virginia Power makes to Hopewell Cogeneration has a clear and ascertainable gross receipts tax tier or "component" in it. Virginia Power witness Jones also included a portion of the Hopewell Cogeneration capacity payments in the long list of those payments which had been calculated including an avoided GRT. Hopewell Cogeneration's Petition neglects to consider Virginia Power's rebuttal testimony in

this case. Even after Messrs. Utt and Shanker testified that the new blended rate was negotiated and therefore could not include an identifiable GRT, Virginia Power maintained that a portion of the Hopewell Cogeneration payments were properly included in Category 4 which included those contracts, or portions thereof, which had rates based on Chesterfield 7 costs, which in turn included GRT. Hopewell Cogeneration was properly included in Category 4. The final rate was based on or included a component that improperly included GRT. Virginia Power admits this and we will not burden ratepayers with costs Virginia Power agrees were based on the error.

Payments to Hopewell Cogeneration are higher than they would have been if 84.15% of the dependable capacity rate had been correctly calculated based on an avoided cost excluding GRT. The evidence that the current Hopewell Cogeneration capacity rate has a component which was calculated based on the erroneous inclusion of GRT is uncontroverted. Therefore, as we said in the February 3 Final Order, purchased power costs here are unnecessary and excessive because an undisputed error was made. When the evidence shows that payments were based on or include a component which is in error and results in excessive costs we must substitute just and reasonable rates for rates based on those excessive costs. Whether it is referred to as a tier or a component in the calculation of a blended rate, any payments which include an identifiable and erroneous GRT component should be included in the calculation of the disallowance ordered here.

On its face, Chesapeake's Petition is more difficult to resolve, but, again, we must remain focused on the issue at hand. Are Virginia Power's costs just and reasonable? It

is Virginia Power which is the subject of the disallowance here, not Chesapeake. Virginia Power witness Carney identified the evolution of the avoided cost methodology used by Virginia Power. He described a marginal analysis which was used to derive a levelized revenue requirement factor applied to the original plant investment thereby providing a constant revenue requirement necessary to recover the capital related costs of owning and operating a plant including return, depreciation, income and property taxes, fixed operating and maintenance expenses and gross receipts taxes. After describing the methodology used, Mr. Carney went on to explain that

> Conceptually, in order to remove the effect of the inclusion of gross receipts tax from the capacity payments, it would first be necessary to recompute the capacity costs after removing the gross receipts tax component from the levelizing factor. Since no detailed work papers exist, we can only assume that the gross receipts tax rate used in deriving the transmission and distribution components of the marginal cost study was also used in developing generation capacity costs.

Contrary to the suggestion in Chesapeake's Petition, the inclusion of gross receipts tax was not in doubt, only the tax rate used in the calculation. Again, although we recognize that due to a clause which Chesapeake and Virginia Power negotiated, Chesapeake may be indirectly affected by our action here, disallowance of Virginia Power's costs are at issue, not the impact on Chesapeake. We know that gross receipts taxes were erroneously included in the capacity costs of Virginia Power and it is reasonable to rely on the only evidence available on this record to determine the

proper level of Virginia Power's disallowance, the testimony of its own witness, Mr. Carney.

Upon consideration of the Petitions filed by Hopewell Cogeneration, Chesapeake and Union Camp, and the record herein, we are of the opinion and find that the relief requested in the Petitions for Reconsideration should be denied; accordingly,

IT IS ORDERED that the relief requested in the Petitions for Reconsideration filed by Hopewell Cogeneration, Chesapeake and Union Camp is denied.

AN ATTESTED COPY hereof shall be sent by the Clerk of the Commission to: Kendrick R. Riggs, Esquire, Virginia Electric and Power Company, 1200 One River Front Plaza, Louisville, Kentucky 40202; Pamela Johnson, Esquire , Virginia Electric and Power Company, P.O. Box 26666, Richmond, Virginia 23261; Evans B. Brasfield, Esquire, Hunton & Williams, Riverfront Plaza, East Tower, 951 East Byrd Street, Richmond, Virginia 23219-4074; Edward L. Petrini, Esquire, Office of the Attorney General, Division of Consumer Counsel, 101 North 8th Street, 6th Floor, Richmond, Virginia 23219; Frann G. Francis, Esquire, 1050 17th Street, N.W., Suite 300, Washington, D.C. 20036; Louis R. Monacell, Esquire, 1200 Mutual Building, Richmond, Virginia 23219-3095; Jean Ann Fox, President, Virginia Citizens Consumer Council, 114 Coachman Drive, Yorktown, Virginia 23693; Edward L. Flippen, Esquire, and Charles H. Tenser, Esquire, Mays & Valentine, P.O. Box 1122, Richmond, Virginia 23208-1122; David B. Kearney, Esquire, City of Richmond, 900 East Broad Street, Suite 300, Richmond, Virginia 23219; Stephen H. Watts, II, Esquire, and Mark J. LaFratta, Esquire, McGuire, Woods,

Battle & Boothe, One James Center, Richmond, Virginia 23219-4030; T. Randolph Perkins, Esquire, 9405 Arrow Point Boulevard, Charlotte, North Carolina 28217; Oliver A. Pollard, III, Esquire, Southern Environmental Law Center, 201 West Main Street, Suite 14, Charlottesville, Virginia 22901; Frederick H. Ritts, Esquire, 1025 Thomas Jefferson Street, N.W., Washington, D.C. 20007; Stanley W. Balis, Esquire, 1101 14th Street, N.W., Suite 1400, Washington, D.C. 20005; Dennis R. Bates, Esquire, Fairfax County Board of Supervisors, 12000 Government Center Parkway, Fairfax, Virginia 22035-0064; Denis Waters Bland, Esquire, College of William and Mary, Williamsburg, Virginia 23187; Donald R. Hayes, Esquire, 1100 H Street, N.W., Washington, D.C. 20080; Eric M. Page, Esquire, 316 West Broad street, Richmond, Virginia 23220-4257; Donald A Fickenscher, Virginia Natural Gas, Inc., 5100 East Virginia Beach Boulevard, Norfolk, Virginia 23502-3488; Timothy R. Dunne, Esquire, P.O. Box 22477, Houston, Texas 77227-2427; Mr. J.B. Hall, Jr., Suite 700, Plantation House, 1108 East Main Street, Richmond, Virginia 23219; Laurence M. Hamric, Esquire, Williams, Mullen, Christian & Dobbins, 1021 East Cary Street, Richmond, Virginia 23210-1320; Marjorie R. Philips, Esquire, 300 South Grand Avenue, Los Angeles, California 90071; Philip F. Abraham, P.O. Box 788, Richmond, Virginia 23206; and to the Divisions of Public Utility Accounting, Economics and Finance and Energy Regulation.

A True Copy
Teste:

/s/ William J. Bridge

Clerk of the
State Corporation Commission

CONSTITUTION OF THE UNITED STATES

ARTICLE VI.

All debts contracted and engagements entered into, before the adoption of this Constitution, shall be as valid against the United States under this Constitution, as under the Confederation.

This Constitution, and the laws of the United States which shall be made in pursuance thereof; and all treaties made, or which shall be made, under the authority of the United States, shall be the supreme law of the land; and the judges in every state shall be bound thereby, any thing in the Constitution or laws of any state to the contrary notwithstanding.

The senators and representatives before mentioned, and the members of the several state legislatures, and all executive and judicial officers, both of the United States and of the several states, shall be bound by oath or affirmation, to support this Constitution; but no religious test shall ever be required as a qualification to any office or public trust under the United States.

PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978, § 210

16 U.S.C. § 824a-3

§ 824a-3. Cogeneration and small power production

(a) Cogeneration and small power production rules

Not later than 1 year after November 9, 1978, the Commission shall prescribe, and from time to time thereafter revise, such rules as it determines necessary to encourage cogeneration and small power production, and to encourage geothermal small power production facilities of not more than 80 megawatts capacity, which rules require electric utilities to offer to--

(1) sell electric energy to qualifying cogeneration facilities and qualifying small power production facilities[1] and

(2) purchase electric energy from such facilities.

Such rules shall be prescribed, after consultation with representatives of Federal and State regulatory agencies having ratemaking authority for electric utilities, and after public notice and a reasonable opportunity for interested persons (including State and Federal agencies) to submit oral as well as written data, views, and arguments. Such rules shall include provisions respecting minimum reliability of qualifying cogeneration facilities and qualifying small power production facilities (including reliability of such

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[1]So in original. Probably should be followed by a comma.

facilities during emergencies) and rules respecting reliability of electric energy service to be available to such facilities from electric utilities during emergencies. Such rules may not authorize a qualifying cogeneration facility or qualifying small power production facility to make any sale for purposes other than resale.

(b) Rates for purchases by electric utilities

The rules prescribed under subsection (a) of this section shall insure that, in requiring any electric utility to offer to purchase electric energy from any qualifying cogeneration facility or qualifying small power production facility, the rates for such purchase--

(1) shall be just and reasonable to the electric consumers of the electric utility and in the public interest, and

(2) shall not discriminate against the qualifying cogenerators or qualifying small power producers.

No such rule prescribed under subsection (a) of this section shall provide for a rate which exceeds the incremental cost to the electric utility of alternative electric energy.

(c) Rates for sales by utilities

The rules prescribed under subsection (a) of this section shall insure that, in requiring any electric utility to offer to sell electric energy to any qualifying cogeneration facility or qualifying small power production facility, the rates for such sale--

(1) shall be just and reasonable and in the public interest, and

(2) shall not discriminate against the qualifying cogenerators or qualifying small power producers.

(d) "Incremental cost of alternative electric energy" defined

For purposes of this section, the term "incremental cost of alternative electric energy" means, with respect to electric energy purchased from a qualifying cogenerator or qualifying small power producer, the cost to the electric utility of the electric energy which, but for the purchase from such cogenerator or small power producer, such utility would generate or purchase from another source.

(e) Exemptions

(1) Not later than 1 year after November 9, 1978, and from time to time thereafter, the Commission shall, after consultation with representatives of State regulatory authorities, electric utilities, owners of cogeneration facilities and owners of small power production facilities, and after public notice and a reasonable opportunity for interested persons (including State and Federal agencies) to submit oral as well as written data, views, and arguments, prescribe rules under which geothermal small power production facilities of not more than 80 megawatts capacity, qualifying cogeneration facilities, and qualifying small power production facilities are exempted in whole or part from the Federal Power Act [16 U.S.C.A. § 791a et seq.], from the Public Utility Holding Company Act [15 U.S.C.A. § 79 et seq.], from State laws and regulations respecting the rates,

or respecting the financial or organizational regulation, of electric utilities, or from any combination of the foregoing, if the Commission determines such exemption is necessary to encourage cogeneration and small power production.

(2) No qualifying small power production facility which has a power production capacity which, together with any other facilities located at the same site (as determined by the Commission), exceeds 30 megawatts, or 80 megawatts for a qualifying small power production facility using geothermal energy as the primary energy source, may be exempted under rules under paragraph (1) from any provision of law or regulation referred to in paragraph (1), except that any qualifying small power production facility which produces electric energy solely by the use of biomass as a primary energy source, may be exempted by the Commission under such rules from the Public Utility Holding Company Act [15 U.S.C.A. § 79 et seq.] and from State laws and regulations referred to in such paragraph (1).

(3) No qualifying small power production facility or qualifying cogeneration facility may be exempted under this subsection from--

(A) any State law or regulation in effect in a State pursuant to subsection (f) of this section,

(B) the provisions of section 210, 211, or 212 of the Federal Power Act [16 U.S.C.A. § 824i, 824j, or 824k] or the necessary authorities for enforcement of any such provision under the Federal Power Act [16 U.S.C.A. § 791a et seq.], or

(C) any license or permit requirement under part I of the Federal Power Act [16 U.S.C.A. § 791a et seq.], and provision under such Act related to such a license or permit requirement, or the necessary authorities for enforcement of any such requirement.

(f) Implementation of rules for qualifying cogeneration and qualifying small power production facilities

(1) Beginning on or before the date one year after any rule is prescribed by the Commission under subsection (a) of this section or revised under such subsection, each State regulatory authority shall, after notice and opportunity for public hearing, implement such rule (or revised rule) for each electric utility for which it has ratemaking authority.

(2) Beginning on or before the date one year after any rule is prescribed by the Commission under subsection (a) of this section or revised under such subsection, each nonregulated electric utility shall, after notice and opportunity for public hearing, implement such rule (or revised rule).

(g) Judicial review and enforcement

(1) Judicial review may be obtained respecting any proceeding conducted by a State regulatory authority or nonregulated electric utility for purposes of implementing any requirement of a rule under subsection (a) of this section in the same manner, and under the same requirements, as judicial review may be obtained under section 2633 of this title in the case of a proceeding to which section 2633 of this title applies.

(2) Any person (including the Secretary) may bring an action against any electric utility, qualifying small power producer, or qualifying cogenerator to enforce any requirement established by a State regulatory authority or nonregulated electric utility pursuant to subsection (f) of this section. Any such action shall be brought only in the manner, and under the requirements, as provided under section 2633 of this title with respect to an action to which section 2633 of this title applies.

(h) Commission enforcement

(1) For purposes of enforcement of any rule prescribed by the Commission under subsection (a) of this section with respect to any operations of an electric utility, a qualifying cogeneration facility or a qualifying small power production facility which are subject to the jurisdiction of the Commission under part II of the Federal Power Act [16 U.S.C.A. § 824 et seq.], such rule shall be treated as a rule under the Federal Power Act [16 U.S.C.A. § 791a et seq.]. Nothing in subsection (g) of this section shall apply to so much of the operations of an electric utility, a qualifying cogeneration facility or a qualifying small power production facility as are subject to the jurisdiction of the Commission under part II of the Federal Power Act.

(2)(A) The Commission may enforce the requirements of subsection (f) of this section against any State regulatory authority or nonregulated electric utility. For purposes of any such enforcement, the requirements of subsection (f)(1) of this section shall be treated as a rule enforceable under the Federal Power Act [16 U.S.C.A. § 791a et seq.]. For purposes of any such action, a State regulatory authority or nonregulated electric utility shall be treated as a person

within the meaning of the Federal Power Act. No enforcement action may be brought by the Commission under this section other than--

(i) an action against the State regulatory authority or nonregulated electric utility for failure to comply with the requirements of subsection (f) of this section[1] or

(ii) an action under paragraph (1).

(B) Any electric utility, qualifying cogenerator, or qualifying small power producer may petition the Commission to enforce the requirements of subsection (f) of this section as provided in subparagraph (A) of this paragraph. If the Commission does not initiate an enforcement action under subparagraph (A) against a State regulatory authority or nonregulated electric utility within 60 days following the date on which a petition is filed under this subparagraph with respect to such authority, the petitioner may bring an action in the appropriate United States district court to require such State regulatory authority or nonregulated electric utility to comply with such requirements, and such court may issue such injunctive or other relief as may be appropriate. The Commission may intervene as a matter of right in any such action.

(i) Federal contracts

No contract between a Federal agency and any electric utility for the sale of electric energy by such Federal agency for resale which is entered into after November 9, 1978, may contain any provision which will have the effect of

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[1]So in original. Probably should be followed by a comma.

preventing the implementation of any rule under this section with respect to such utility. Any provision in any such contract which has such effect shall be null and void.

(j) Definitions

For purposes of this section, the terms "small power production facility", "qualifying small power production facility", "qualifying small power producer", "primary energy source", "cogeneration facility", "qualifying cogeneration facility", and "qualifying cogenerator" have the respective meanings provided for such terms under section 3(17) and (18) of the Federal Power Act [16 U.S.C.A. § 796(17), (18)].

18 C.F.R. Part 292

§ 292.304 Rates for purchases

(a) *Rates for purchases.* (1) Rates for purchases shall:

(i) Be just and reasonable to the electric consumer of the electric utility and in the public interest; and

(ii) Not discriminate against qualifying cogeneration and small power production facilities.

(2) Nothing in this subpart requires any electric utility to pay more than the avoided costs for purchases.

(b) *Relationship to avoided costs.* (1) For purposes of this paragraph, "new capacity" means any purchase from capacity of a qualifying facility, construction of which was commenced on or after November 9, 1978.

(2) Subject to paragraph (b)(3) of this section, a rate for purchases satisfies the requirements of paragraph (a) of this section if the rate equals the avoided costs determined after consideration of the factors set forth in paragraph (e) of this section

(3) A rate for purchases (other than from new capacity) may be less than the avoided cost if the State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or the nonregulated electric utility determines that a lower rate is consistent with paragraph (a) of this section, and is sufficient to encourage cogeneration and small power production.

(4) Rates for purchases from new capacity shall be in accordance with paragraph (b)(2) of this section, regardless of whether the electric utility making such purchases is simultaneously making sales to the qualifying facility.

(5) In the case in which the rates for purchases are based upon estimates of avoided costs over the specific term of the contract or other legally enforceable obligation, the rates for

such purchases do not violate this subpart if the rates for such purchases differ from avoided costs at the time of delivery.

(c) *Standard rates for purchases.* (1) There shall be put into effect (with respect to each electric utility) standard rates for purchases from qualifying facilities with a design capacity of 100 kilowatts or less.

(2) There may be put into effect standard rates for purchases from qualifying facilities with a design capacity of more than 100 kilowatts.

(3) The standard rates for purchases under this paragraph:

(i) Shall be consistent with paragraphs (a) and (e) of this section; and

(ii) May differentiate among qualifying facilities using various technologies on the basis of the supply characteristics of the different technologies.

(d) *Purchases "as available" or pursuant to a legally enforceable obligation.* Each qualifying facility shall have the option either:

(1) To provide energy as the qualifying facility determines such energy to be available for such purchases, in which case the rates for such purchases shall be based on the purchasing utility's avoided costs calculated at the time of delivery; or

(2) To provide energy or capacity pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term, in which case the rates for such purchases shall, at the option of the qualifying facility exercised prior to the beginning of the specified term, be based on either:

(i) The avoided costs calculated at the time of delivery; or

(ii) The avoided costs calculated at the time the obligation is incurred.

(e) *Factors affecting rates for purchases.* In determining avoided costs, the following factors shall, to the extent practicable, be taken into account:

(1) The data provided pursuant to §292.302(b), (c), or (d), including State review of any such data;

(2) The availability of capacity or energy from a qualifying facility during the system daily and seasonal peak periods, including:

(i) The ability of the utility to dispatch the qualifying facility;

(ii) The expected or demonstrated reliability of the qualifying facility;

(iii) The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement and sanctions for non-compliance;

(iv) The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the utility's facilities;

(v) The usefulness of energy and capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation;

(vi) The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system; and

(vii) The smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities; and

(3) The relationship of the availability of energy or capacity from the qualifying facility as derived in paragraph (e)(2) of this section, to the ability of the electric utility to

avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use; and

(4) The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a qualifying facility, if the purchasing electric utility generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity.

(f) *Periods during which purchases not required.* (1) Any electric utility which gives notice pursuant to paragraph (f)(2) of this section will not be required to purchase electric energy or capacity during any period during which, due to operational circumstances, purchases from qualifying facilities will result in costs greater than those which the utility would incur if it did not make such purchases, but instead generated an equivalent amount of energy itself.

(2) Any electric utility seeking to invoke paragraph (f)(1) of this section must notify, in accordance with applicable State law or regulation, each affected qualifying facility in time for the qualifying facility to cease the delivery of energy or capacity to the electric utility.

(3) Any electric utility which fails to comply with the provisions of paragraph (f)(2) of this section will be required to pay the same rate for such purchase of energy or capacity as would be required had the period described in paragraph (f)(1) of this section not occurred.

(4) A claim by an electric utility that such a period has occurred or will occur is subject to such verification by its State regulatory authority as the State regulatory authority determines necessary or appropriate, either before or after the occurrence.

§ 292.602 Exemption to qualifying facilities from the Public Utility Holding Company Act and certain State law and regulation.

(a) *Applicability.* This section applies to any qualifying facility described in § 292.60(a), and to any qualifying small power production facility with a power production capacity over 30 megawatts if such facility produces electric energy solely by the use of biomass as a primary energy source.

(b) *Exemption from the Public Utility Holding Company Act of 1935.* A qualifying facility described in paragraph (a) of this section or a utility geothermal small power production facility shall not be considered to be an "electric utility company" as defined in section 2(a)(3) of the Public Utility Holding Company Act of 1935, 15 U.S.C. 79b(a)(3).

(c) *Exemption from certain State law and regulation.* (1) Any qualifying facility shall be exempted (except as provided in paragraph (c)(2) of this section from State law or regulation respecting:

(i) The rates of electric utilities; and

(ii) The financial and organizational regulation of electric utilities.

(2) A qualifying facility may not be exempted from State law and regulation implementing subpart C.

(3) Upon request of a state regulatory authority or nonregulated electric utility, the Commission may consider a limitation on the exemptions specified in paragraph (c)(1) of this section.

(4) Upon request of any person, the Commission may determine whether a qualifying facility is exempt from a particular State law or regulation.